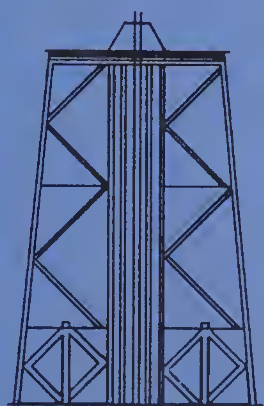
Biological Services Program

FWS/OBS–77/12
March 1978

Environmental Planning for Offshore Oil and Gas

Volume I:

Recovery Technology



Fish and Wildlife Service

U.S. Department of the Interior

The Biological Services Program was established within the U.S. Fish and Wildlife Service to supply scientific information and methodologies on key environmental issues that impact fish and wildlife resources and their supporting ecosystems. The mission of the program is as follows:

- To strengthen the Fish and Wildlife Service in its role as a primary source of information on national fish and wildlife resources, particularly in respect to environmental impact assessment.

- To gather, analyze, and present information that will aid decisionmakers in the identification and resolution of problems associated with major changes in land and water use.

- To provide better ecological information and evaluation for Department of the Interior development programs, such as those relating to energy development.

Information developed by the Biological Services Program is intended for use in the planning and decisionmaking process to prevent or minimize the impact of development on fish and wildlife. Research activities and technical assistance services are based on an analysis of the issues a determination of the decisionmakers involved and their information needs, and an evaluation of the state of the art to identify information gaps and to determine priorities. This is a strategy that will ensure that the products produced and disseminated are timely and useful.

Projects have been initiated in the following areas: coal extraction and conversion; power plants; geothermal, mineral and oil shale development; water resource analysis, including stream alterations and western water allocation; coastal ecosystems and Outer Continental Shelf development; and systems inventory, including National Wetland Inventory, habitat classification and analysis, and information transfer.

The Biological Services Program consists of the Office of Biological Services in Washington, D.C., which is responsible for overall planning and management; National Teams, which provide the Program's central scientific and technical expertise and arrange for contracting biological services studies with states, universities, consulting firms, and others; Regional Staff, who provide a link to problems at the operating level; and staff at certain Fish and Wildlife Service research facilities, who conduct inhouse research studies.

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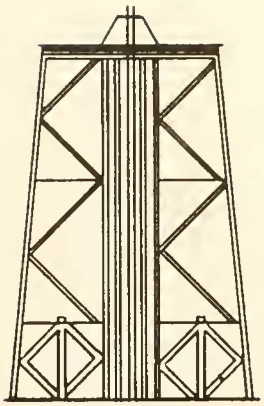

Environmental Planning for Offshore Oil and Gas

Volume I: Recovery Technology

by

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Environmental Planning for Offshore Oil and Gas

Volume I: Recovery Technology

Volume II: Effects on Coastal Communities

Volume III: Effects on Living Resources and Habitats

Volume IV: Regulatory Framework for Protecting Living Resources

Volume V: Regional Status Reports:

- Part 1: New England
- Part 2: Mid and South Atlantic
- Part 3: Gulf Coast
- Part 4: California
- Part 5: Alaska, Washington and Oregon

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ENVIRONMENTAL PLANNING FOR OFFSHORE OIL AND GAS

FOREWORD

This report is one in a series prepared by The Conservation Foundation for the Office of Biological Services of the U.S. Fish and Wildlife Service (Contract 14-16-0008-962). The series conveys technical information and develops an impact assessment system relating to the recovery of oil and gas resources beyond the three-mile territorial limit of the Outer Continental Shelf (OCS). The series is designed to aid Fish and Wildlife Service personnel in the conduct of environmental reviews and decisions concerning OCS oil and gas development. In addition, the reports are intended to be as helpful as possible to the public, the oil and gas industry, and to all government agencies involved with resource management and environmental protection.

Oil and gas have been recovered for several decades from the Outer Continental Shelf of Texas, Louisiana and California. In the future, the Department of the Interior plans to lease more tracts, not only off these coasts, but also off the frontier regions of the North, Mid- and South Atlantic, eastern Gulf of Mexico, Pacific Northwest and Alaska. Within the set of constraints imposed by the international petroleum market (including supply, demand and price), critical decisions are made jointly by industry and government on whether it is advisable or not to move ahead with leasing and development of each of the offshore frontier areas. Once the decision to develop a field is made, many other decisions are necessary, such as where to locate offshore platforms, where to locate the onshore support areas, and how to transport hydrocarbons to market.

Existing facilities and the size of the resource will dictate which facilities will be needed, what the siting requirements will be, and where facilities will be sited. If the potential for marketable resources is moderate, offshore activities may be staged from areas already having harbor facilities and support industries; therefore, they may have little impact on the coast adjacent to a frontier area. An understanding of these options from industry's perspective will enable Fish and Wildlife Service personnel to anticipate development activities in various OCS areas and to communicate successfully with industry to assure that fish and wildlife resources will be protected.

The major purpose of this report is to describe the technological characteristics and planning strategy of oil and gas development on the Outer Continental Shelf, and to assess the effects of OCS oil and gas operations on living resources and their habitats. This approach should help bridge the gap between a simple reactive mode and effective advanced planning--planning that will result in a better understanding of the wide range of OCS activities that directly and indirectly generate impacts on the environment, and the countermeasures necessary to protect and enhance living resources.

Development of offshore oil and gas resources is a complex industrial process that requires extensive advance planning and coordination of all phases from exploration to processing and shipment. Each of hundreds of system components linking development and production activities has the potential for adverse environmental effects on coastal water resources. Among the advance judgements that OCS planning requires are the probable environmental impacts of various courses of action.

The relevant review functions that the Fish and Wildlife Service is concerned with are: (1) planning for baseline studies and the leasing of oil and gas tracts offshore and (2) reviewing of permit applications and evaluation of environmental impact statements (EIS) that relate to facility development, whether offshore (OCS), near shore (within territorial limits), or onshore (above the mean high tidemark). Because the Service is involved with such a broad array of activities, there is a great deal of private and public interest in its review functions. Therefore, it is most valuable in advance to have some of the principles, criteria and standards that provide the basis for review and decisionmaking. The public, the offshore petroleum industry, and the appropriate Federal, state, and local government agencies are thus able to help solve problems associated with protection of public fish and wildlife resources. With advanced standards, all interests should be able to gauge the environmental impacts of each OCS activity.

A number of working assumptions were used to guide various aspects of the analysis and the preparation of the report series. The assumptions relating to supply, recovery, and impacts of offshore oil and gas were:

1. The Federal Government's initiative in accelerated leasing of OCS tracts will continue, though the pace may change.

2. OCS oil and gas extractions will continue under private enterprise with Federal support and with Federal regulation.

3. No major technological breakthroughs will occur in the near future which could be expected to significantly change the environmental impact potential of OCS development.

4. In established onshore refinery and transportation areas, the significant impacts on fish and wildlife and their habitats will come from the release of hydrocarbons during tanker transfers.

5. A significant potential for both direct and indirect impacts of OCS development on fish and wildlife in frontier areas is expected from site alterations resulting from development of onshore facilities.

6. The potential for onshore impacts on fish and wildlife generally will increase, at least initially, somewhat in proportion to the level of onshore OCS development activity.

The assumptions related to assessment of impacts were:

1. There is sufficient knowledge of the effects of OCS development activities to anticipate direct and indirect impacts on fish and wildlife from known oil and gas recovery systems.

2. This knowledge can be used to formulate advance criteria for conservation of fish and wildlife in relation to specific OCS development activities.

3. Criteria for the protection of environments affected by OCS-related facilities may be broadly applied to equivalent non-OCS-related facilities in the coastal zone.

The products of this project--reported in the series Environmental Planning for Offshore Oil and Gas--consist of five technical report volumes. The five volumes of the technical report series are briefly described below:

Volume I — Reviews the status of oil and gas resources of the Outer Continental Shelf and programs for their development; describes the recovery process step-by-step in relation to existing environmental regulations and conservation requirements; and provides a detailed analysis for each of fifteen OCS activity and facility development projects ranging from exploration to petroleum processing.

Volume II Discusses growth of coastal communities and effects on living resources induced by OCS and related onshore oil and gas development; reports methods for forecasting characteristics of community development; describes employment characteristics for specific activities and onshore facilities; and reviews environmental impacts of probable types of development.

Volume III Describes the potential effects of OCS development on living resources and habitats; presents an integrated system for assessment of a broad range of impacts related to location, design, construction, and operation of OCS-related facilities; provides a comprehensive review of sources of ecological disturbance for OCS related primary and secondary development.

Volume IV Analyzes the regulatory framework related to OCS impacts; enumerates the various laws governing development offshore; and describes the regulatory framework controlling inshore and onshore buildup in support of OCS development.

Volume V In five parts, reports current and anticipated OCS development in each of five coastal regions of the United States: New England; Mid and South Atlantic: Gulf Coast; California; and Alaska, Washington and Oregon.

John Clark was The Conservation Foundation's project director for the OCS project. He was assisted by Dr. Jeffrey Zinn, Charles Terrell and John Banta. We are grateful to the U.S. Fish and Wildlife Service for its financial support, guidance and assistance in every stage of the project.

William K. Reilly
President
The Conservation Foundation

ENVIRONMENTAL PLANNING FOR OFFSHORE OIL AND GAS

PREFACE

This report is presented in two parts. Part 1 introduces the offshore oil and gas industry, starting with the demand for energy and available resources and leading to the current national program to develop offshore oil and gas. Part 2 discusses the specific offshore and onshore activities involved in the recovery of offshore oil and gas, and describes in detail each of fifteen major development phases along with related activities and facilities. For each activity/facility development type the site requirements are described, along with construction and operation, community factors, effects on living resources, and regulatory factors. The report gives particular attention to the strategies the Outer Continental Shelf (OCS) industries use in making investment, location, and timing decisions.

While the goal of the whole OCS project is to provide a basis for assessing the broadest range of direct and induced impacts on resources within the jurisdiction of the U.S. Fish and Wildlife Service, Volume I is mainly concerned with physical description of offshore oil and gas development activities as (1) a direct cause of impacts offshore and (2) a generator of indirect impacts inshore and onshore.

The report discusses where the oil industry's activities are currently located, where future efforts are planned, where known natural resources are located, where the most promising new fields may be found, where seismic surveying operations are currently focused, where drilling is anticipated, and where pipelines, transshipment terminals and refineries are being planned and built. The extent to which the United States will depend on imported products and where and how these products will enter the United States are briefly discussed.

The information in this report was collected from a wide variety of sources: the coastal document center of The Conservation Foundation; other libraries and relevant literature sources; unpublished files; data exchange with other ongoing OCS studies; and interviews and direct field observations. To the extent possible, the information is current to mid-year 1976.

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ACKNOWLEDGEMENTS

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PART I -- RESOURCES AND RECOVERY

Section 1.1 presents forecasts for demands on the potential supply of energy to the year 2000. Petroleum resources to meet that demand are estimated for the nation, both onshore and offshore. United States production trends, now declining, have had a strong effect on worldwide resource and production trends. Production locations have been the primary factor in locating oil refineries and petroleum infrastructure, discussed in the conclusion of this section.

Section 1.2 discusses the offshore development potentials, problems and programs including the geologic potential of the continental shelf and of proposed lease areas. Offshore resource estimates are presented, followed by the schedule for the Federal program to lease and develop the Outer Continental Shelf.

Section 1.3 introduces the six major phases involved in the offshore development process--pre-exploration, geological and geophysical exploration, exploratory drilling, field development, production and shutdown of facilities--and time constraints on industry development.

1.1 PETROLEUM DEMANDS AND RESOURCES

It is widely accepted that the major source of domestic energy during the next quarter of a century will be oil and gas. New energy sources appear too expensive and pollution prone to meet a significant portion of domestic energy needs at present despite the efforts made to develop them. An era characterized by abundant and cheap energy has ended, and the world is undergoing a painful readjustment characterized by increasing demand and reduced supplies of energy.

This section presents the overall national demand for energy supply and the anticipated role of oil and gas in meeting these demands through the year 2000. The amount of petroleum resources--and domestic production--are now declining, especially onshore. This has led to a larger share of production for offshore oil and gas. Worldwide, the increased demand and decreased supply in the United States has led to dramatic shifts in resources and production from the Western Hemisphere to the Eastern--especially the Middle East.

Since the first commercial oil well was drilled in Pennsylvania in 1859, petroleum has been a significant factor in our nation's growth and development. Oil did not replace coal as the primary U.S. energy source until the 1940's, but even before that, it was a critical commodity and played a vital role in national changes in lifestyle. In the past 30 years, the value of petroleum has spread far beyond fuels. It has become a required ingredient for a broad range of standard commodities from drugs to plastics and synthetic fibers.

1.1.1 National Demand and Supply of Energy

For 100 years the United States was blessed by an abundance of petroleum resources. But in recent years our reserves have shrunk drastically as our rate of consumption has surpassed our ability to produce from domestic sources. Until 1948, the United States was a net exporter of petroleum, but since then our consumption has exceeded domestic production. At present, our nation is dependent on petroleum imports for over 40 percent of our oil demand. The percentage of imports is predicted to increase to over 50 percent before the end of the 1970's.

Two other factors are expected to have significant effects on energy source options: (1) the percentage of imports may increase even further if other fuel sources such as coal or nuclear power are produced at a slower rate than predicted and, (2) more than half of the domestic production of oil and gas that will be consumed during this century must be derived from new and as yet unknown resource deposits.

The Federal Energy Administration (FEA) forecasts that nuclear power plants will not be built as rapidly as had been projected in the past. According to FEA [1] coal production should rise by 1985, perhaps exceeding 1 billion tons (compared to 639 million tons in 1974).

Solar energy, which has been widely heralded as the new energy source of the future, is expected to account for not more than 10 percent of the total U.S. energy supply by the year 2000 and up to 45 percent in 2020 according to the U.S. Energy Research and Development Administration (ERDA). Other sources of energy such as wind and geothermal are not predicted to contribute more than a few percent.

While oil and gas may remain the dominant fuels for the next 25 years in the United States, their share of the total energy supply is expected to drop from the present 76 percent to 59 percent by the year 2000, as shown in Table 1. Use of coal will remain relatively constant, while both nuclear and solar power should increase their shares. Table 1 indicates the projected ratio of the domestic energy supply sources for the period 1975-2000. The projection for the year 2000 uses a recent forecast by the Exxon Corporation [2] and incorporates other information to predict the situation at the end of the century.

Table 1. Distribution of U.S. Energy Supply, 1950-1990 (in Percent of BTU's). (Sources: 1950 Data, Reference 2; 1975-1990 Data, Reference 1)

Source	YEAR 1950 (%)	1975 (%)	1980 (%)	1990 (%)
Nuclear	0	2	6	17
Hydro/Geothermal	5	4	4	3
Coal	38	18	19	17
Gas	18	29	22	21
Oil	39	47	49	42
Solar	0	0	0	0

1.1.2 Status of U.S. Oil and Gas Resources

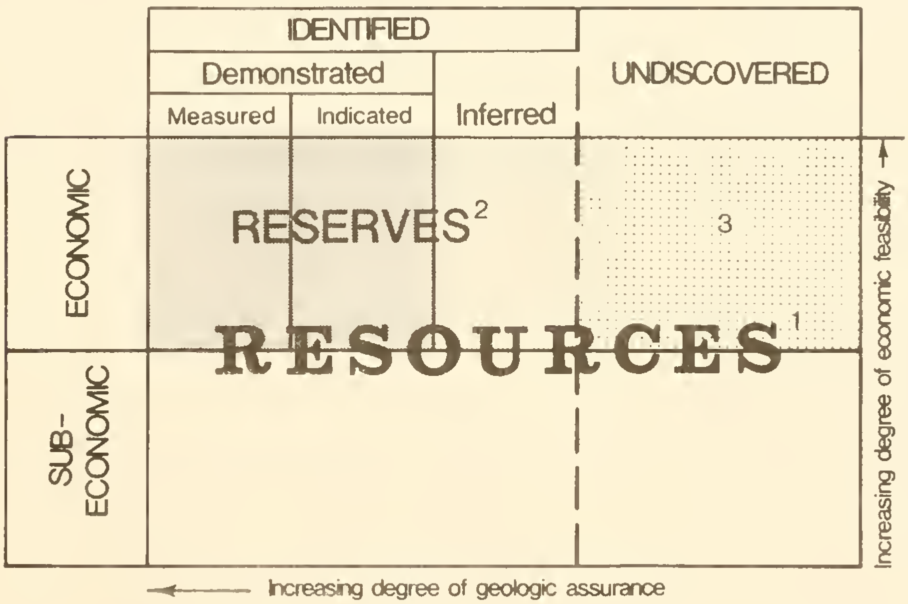
Cumulative production of oil in the United States from 1849 through 1974 amounted to 106.1 billion barrels, according to the U.S. Geological Survey [3]. The amount of oil remaining has been estimated by USGS, by classifications shown in Figure 1. Identified reserves are estimated to be 68 billion barrels (statistical mean of high and low estimates), or 63 percent of the total already produced. USGS has further estimated "undiscovered recoverable resources," those economic resources not yet discovered which are estimated to exist in favorable geological environments, to range between 50 and 127 billion barrels of oil. The statistical mean of these estimates is 86 billion barrels.

In comparison to the 481 trillion cubic feet of natural gas produced through 1974, there are identified reserves of 439 trillion cubic feet and undiscovered recoverable resources of 484 trillion cubic feet (statistical means). The latter estimate has a range between 322 and 655 trillion cubic feet of natural gas [3].

While these estimates indicate a supply available for many years, the level of proven reserves--which increased for many years with new

discoveries--has been declining recently. Consumption has been rising faster than discoveries. In 1975 (the latest information available) oil reserves declined by about 5 percent, and natural gas reserves declined nearly 4 percent.

Figure 1. Petroleum resource terms and classification system (Source: Reference 3).



1. Resources - naturally occurring materials concentrated so that economic extraction is potentially feasible.

2. Reserves - that portion of resources which are presently economically extractable.

3. Undiscovered recoverable resources - those economic resources yet undiscovered which are estimated to exist in favorable geologic environments.

The present poor condition of our natural petroleum resource is well demonstrated by the critical declines in the big, Gulf of Mexico producing states, Texas and Louisiana. Texas, the leading U.S. oil producer since 1928, which presently produces over 40 percent of the Nation's crude oil, has seen its measured reserves of crude drop from a peak of 13.0 billion barrels in 1971 to 10.1 billion barrels as of January 1, 1975. Louisiana's measured reserves have declined from 5.7 billion barrels in 1970 to 3.8 billion barrels in 1975.

1.1.3 U.S. Production Trends

While U.S. crude production slumped in the mid-1970's, industry has forecast a long term increase in production until 1990 (Table 2), but it is

Table 2. Projected U.S. Oil and Gas Production to the Year 1990 in Millions of Barrels Per Day (Two Trillion Cubic Feet of Gas/Year Equals One Million Barrels/Day Oil Equivalent) (Source: Reference 2)

Production	Year		
	1975	1980	1990
Oil Production			
Conventional[1]	10.6	10.8	11.8
Non-conventional[2]	0.0	0.1	1.6
Imports	6.3	10.6	12.0
	16.9	21.5	25.4
Gas Production	1975	1980	1990
Conventional[1]	20.7	16.2	19.3
Synthetic[3]	0.2	0.5	2.2
Imports	1.0	2.0	3.5
Subtotal	21.9	18.7	25.0

1. Oil and gas fields tapped by drilling wells.
2. Oil created from oil shale or coal liquification.
3. Gas created from coal gasification.

believed that thereafter there will be a progressive decline. This may be offset to some extent by non-conventional ("synthetic") oil derived from oil shale and coal. Conventional gas supplies have been forecast to decline up to 1980, then increase until 1990 as new fields are discovered. There will then be a period of continued decline into the twenty first century. Similar to oil, it is anticipated that synthetic gas from coal (along with increased imports, mostly in the form of liquefied natural gas), may take up the slack in domestic output.

While the projected supply of "conventional" domestic oil and gas is relatively constant, production from existing known reserves will decline; the balance will be made up by new discoveries. It is believed that by 1990, production from existing known oil reserves will amount to only 5 million barrels per day and that production from existing known gas reserves will amount to only 8 trillion cubic feet (Tcf) per year or 4 million-barrels-per-day oil-equivalent. It is expected that as much as 40 to 50 percent of the new discoveries will be offshore fields and the total offshore production will rise accordingly.

1.1.4 Offshore Production and Activity

While exploration of land areas will be vigorously pursued, the offshore area represents the "last frontier" in U.S. petroleum exploration. In the past 15 years the United States has so greatly accelerated offshore oil and gas development that it now accounts for a substantial part of total domestic output. Many trends can be discerned from the data presented in Table 3 which shows the domestic total and offshore oil and gas production from 1960 to 1974.

Total onshore and offshore oil production increased incrementally from 1960 to 1970 but now has declined from that peak period by about 20 percent.

The significance of offshore oil to the total domestic supply picture is indicated by a comparison of its contribution of 4 percent in 1960 to the more than 18 percent in 1973. Offshore oil production quadrupled during the 1960's, peaked in the early 1970's and then declined about 7 percent. The production of offshore natural gas showed an even more impressive growth. It increased almost sevenfold in the 1960-69 period, reached a maximum in 1971, and since that time has declined by about 30 percent.

It is generally conceded that offshore production will account for an ever-increasing percentage of total U.S. production; within the next 15 to 25 years offshore petroleum may account for as much as 40 to 50 percent of all domestic production. In U.S. offshore areas there were 1,029 wells and 1,128 wells drilled, respectively, in 1973 and 1974. The number of wells drilled in recent years has remained below 1,000. While these statistics indicate that there may be no overall

increase in U.S. offshore drilling, activities could increase significantly in frontier areas where drilling has not yet occurred if large discoveries are made.

Table 3. U.S. Offshore Oil and Gas Production in Relation to Total Production, 1960-1974 (Source: Reference 4).

	Crude Oil Production (millions of barrels)			Natural Gas Production (billions of cubic feet)		
	Total	Offshore	% Offshore To Total	Total	Offshore	% Offshore To Total
1960	2907	117	4.0	15088	440	2.9
1961	2984	133	4.5	15460	478	3.1
1962	3049	162	5.3	16039	640	4.0
1963	3154	188	6.0	16973	763	4.5
1964	3201	215	6.7	17440	850	4.9
1965	3290	243	7.4	17963	939	5.2
1966	3496	298	8.5	19034	1372	7.2
1967	3730	352	9.4	20252	1830	9.1
1968	3869	419	10.8	21325	2299	10.8
1969	3959	465	11.7	22679	2800	12.4
1970	4123	506	12.3	23787	3136	13.2
1971	4101	549	13.4	24104	3667	15.2
1972	3450	472	13.7	22897	3325	14.5
1973	3361	620	18.4	22854	2603	11.4
1974	3199	521	16.3	22377	2374	10.6

1.1.5 Worldwide Resources and Production Trends

Of all the trends occurring in the worldwide petroleum business, the most important is the current shifting of measured reserves and production from the U.S. and Western Hemisphere to the Eastern Hemisphere--the Persian Gulf nations, the western and northern African nations, and Indonesia along with several other Southeast Asian countries. All of these areas are presently supplying significant imports to the United States. The dramatic North Sea and Prudhoe Bay discoveries have caused a temporary increase in the United States and Western European supply.

Over 85 percent of the world's hydrocarbon production and reserves occur in less than 5 percent (238 fields) of all producing accumulations [5]. Sixty-five percent of the reserves occur in less than one percent of the fields. The 55 "supergiant" fields (scattered throughout the world) each contain over a billion barrels of oil (or a trillion cubic feet of natural gas). Fifteen percent of reserves occur in two immense Persian Gulf fields--Ghawan in Saudi Arabia and Burgan in Kuwait.

More than anything else, the shift in the geographical location of reserves and production has meant, and will mean, a transition from traditional patterns of production, transportation, and refining of hydrocarbons to new patterns with oil and gas flowing from the reserve rich countries to U.S. refining and distribution centers. It is these patterns, defined by the worldwide flow of Eastern Hemisphere oil and gas, which will determine the trends in the U.S. petroleum infrastructure for at least the next 20 years. Unless an unexpectedly large reserve is found offshore in U.S. frontier areas, any discoveries or production from the offshore will not alter the trends set by foreign imports (imports, however, could be affected by significant conservation efforts). Domestic production from offshore will simply displace foreign hydrocarbons to other regions of the nation or be added to a region's input stream. Therefore, vast growth of refining and distribution systems will not likely be induced by offshore finds, unless they are unexpectedly high.

1.1.6 Location of Refineries and Other Infrastructure

The easiest way to explain how the infrastructure of the U.S. oil industry is presently distributed is to say that it is organized around the historical sources of oil and gas, areas which have had the largest concentration of producing fields. Therefore, the heaviest concentrations of infrastructures are in the Texas and Louisiana coastal region. The pipelines and refineries in these areas have, in the past, been supplied from local fields but now are increasingly supplied from imports coming in through the region's many tanker terminals.

How offshore development in any "frontier" area will affect nearby coastal communities depends on its relation to the existing pattern of

industry infrastructure. Particularly important is the geography of crude oil pipelines, transshipment terminals, refineries, product pipelines, and the technical and business organizations that build and operate such facilities. Existing infrastructure is of great importance because it requires an immense fixed and working capital investment that can neither be abandoned nor moved to a new location. At best, existing infrastructures that is undesirably located (in an economic sense) with respect to new offshore sources of crude oil will be gradually phased out by industry as it rebuilds and reorganizes around the newer energy sources. Therefore, a new OCS field may not be accompanied by a huge buildup of facilities on the nearest adjacent coast. Contrariwise, one would expect that platforms would be built at existing yards, that the crude product would go for processing to present refineries and that only service facilities would spring up immediately in the local area.

In addition to Texas and Louisiana, there are sizable concentrations of infrastructure in Southern California and along the east coast in New York, Pennsylvania, New Jersey, Delaware and Maryland. Infrastructure is also spread throughout the north central states. For years, the east coast infrastructure has been supported by oil imported via tankers; thus it is near existing harbors. Much of this infrastructure was built to handle imports from the Caribbean Islands.

Refineries in the Caribbean Islands have historically processed heavy South American crudes (mainly from Venezuela) into residual oils for the east coast utility (mostly electric power) market. As Venezuelan oil production has declined, these refineries have turned to eastern hemisphere crude sources.

It appears that an excess of refining capacity will be available in the Caribbean for some time. Since the Caribbean Islands lie directly on the route of tankers from the Persian Gulf, this area has become highly favored as a refining and transshipment center. Transshipment seems feasible since oil can be transported to the Caribbean in supertankers and then moved to the U.S. in shallower draft tankers capable of directly entering all U.S. ports.

The availability of crude oil to a region is the most critical factor affecting the establishment and growth of refining capacity. On a large geographic scale, as crude sources shift, refining capacity will do likewise, continuing to locate where crude can be made readily available.

Also, refinery location is dependent on the availability of water for two reasons. First, location of refineries in proximity to navigable waterways allows inexpensive transport of oil and products. Second, large quantities of water are used for cooling in the refining process.

The Gulf Coast region has more refining capacity than any other region of the United States--41 percent of the total. This compares to

46 percent for the three next largest producing regions combined: the North, and North Central, Pacific Coast, and Mid Atlantic Coast. The abundance of refining capacity in the Gulf Coast region is simply the result of the prolific production of the oil fields of Texas, Louisiana, and the Gulf of Mexico. The proximity of Gulf Coast refining capacity to navigable waters, especially deep water, has also given it access to yet another source of crude foreign imports. For years, Gulf Coast refineries have received Venezuelan oil and now are increasingly receiving eastern hemisphere crude.

From the Gulf Coast refining region, large diameter product pipelines extend throughout the southeast and into the northeast as far as the Mid Atlantic coastal region. The main pipelines are the Dixie, Plantation, and Colonial systems.

The refining capacity of the mid-continent region was originally constructed in response to the oil production of the Oklahoma and eastern Kansas fields. In recent years, as mid-continent crude production has declined, its growth has been fueled by crude piped in from the Gulf Coast region. Future crude supplies will probably come from abroad. It appears that crude imports will be brought in through the proposed Seadock "deepwater port" (an offshore anchored transfer station) off Freeport, Texas, and then move northward through numerous crude pipelines. Two new crude lines are presently under construction to handle these probable imports: (1) Seaway Pipeline Company's new 36-inch diameter pipeline to Cushing, Oklahoma, and (2) the 426-mile 26-inch Texoma line from Nederland, Texas, to Cushing, Oklahoma.

The refining capacity of the North Central region grew prior to the 1950's in response to oil production in southern Illinois and Indiana, and in Ohio. This growth has been sustained in recent years by Gulf Coast crude and by imported crude piped into the region via the Central American Pipeline system (CAPLINE) and the Mid-Valley system.

The refining capacity of the Mid Atlantic coast has run primarily on imported oil tankered into the region. Imports have come predominantly from Venezuela and the Caribbean, but these sources are gradually being displaced by eastern hemisphere crude predominantly from Nigeria and the Persian Gulf, and to some extent, from North Africa. Most of this area's refining capacity is located in the coastal zone , with product distribution throughout this region and the Northeast handled by small tankers and barges.

The Mid Atlantic region, despite being the most heavily populated in the U.S., has only 11 percent of the Nation's refining capacity. A main reason for this is that the Mid Atlantic receives refined products via pipelines from the Gulf Coast region and via smaller tankers from the Caribbean where, in both cases, there are refineries located in proximity to the oil fields.

The Pacific Coast refining capacity is centered primarily in Southern California in the Los Angeles-Bakersfield area, adjacent to major oil fields. Oil processed in these refineries has come from onshore Southern California fields and offshore in the Santa Barbara Channel. Today, because California production has stabilized, while demand has grown, oil is being imported from the Persian Gulf and from Indonesia. Other Pacific Coast refining centers are in the San Francisco Bay area and on Puget Sound in Washington state.

A significant future source of crude for the entire Pacific Coast region, probably beginning in 1977, will be Alaskan oil. This will not, however, exclude all foreign oil. Plans are proposed to pipe much of the Alaskan oil east to mid-continent and North Central refineries.

1.1.7 Natural Gas

The first known use of natural gas was in upstate New York in 1821. Gas for home use was distributed by numerous local gas utilities which manufactured it from coal. The large steel gas storage tanks still standing in many major cities are a reminder of that period. However, in 1947, a major change took place when natural gas from Texas and Louisiana flowed to the East Coast through two converted liquid pipelines, the "Big Inch" and the "Little Inch". Since that time, the consumption of natural gas has mushroomed for residential, industrial, commercial, and power generation uses. This growth was promoted by several factors including: the availability of new markets; the replacement of coal by gas for space heating, for industrial processing, and for the production of fertilizers and petrochemicals; and the urgent demand for low-sulfur fuels that occurred in the late 1960's in response to environmental legislation. Local utility gas mains increased more than four-fold in the 25 years between 1945 and 1970. The U.S. high-pressure natural gas transmission network has now been extended into all of the lower 48 states.

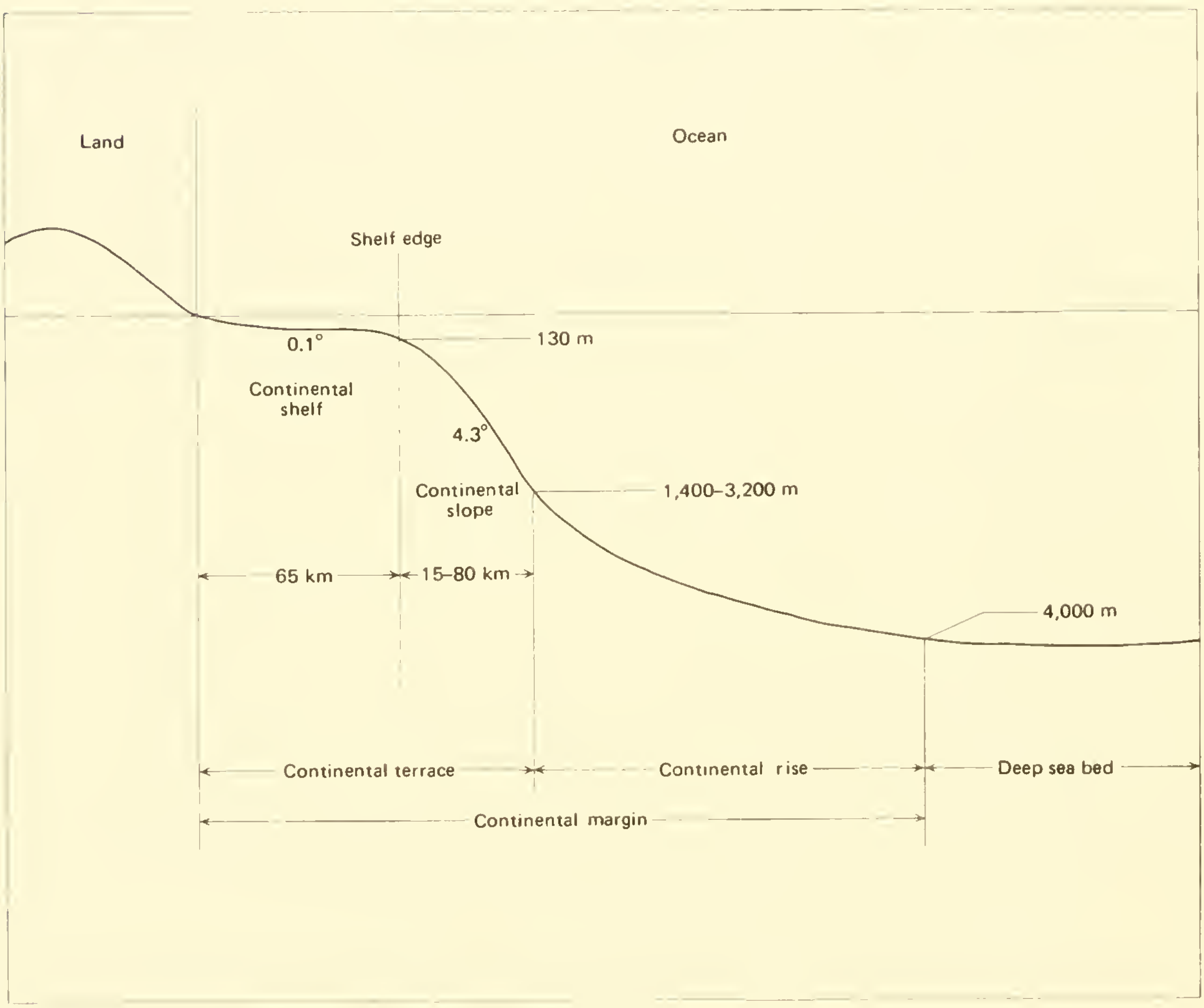
1.2 PROBLEMS AND POTENTIALS OF OFFSHORE DEVELOPMENT

National trends in energy demands and petroleum supply have led to a renewed interest in the offshore for development of oil and gas. In this section, we discuss the features of the continental shelf and the geologic potential of offshore areas in general and proposed lease areas specifically. Resource estimates have been made for each of these areas, and programs designed for their development. The section concludes with a detailed discussion of the BLM leasing program currently underway.

1.2.1 The Continental Shelf

The oil and gas industry's prosperity depends upon the recurrent discovery of hydrocarbons and the continental margins of the world are prime candidates for their location. The Continental Shelf is a gently sloping plateau of land that starts at the coastline and runs seaward to a point where there is a sharply defined drop toward the ocean floor. Figure 2 depicts the characteristic features of the continental margin, which includes the continental shelf.

Figure 2. An example profile of the continental margin (Source: Reference 6).



On a global scale, the total continental margin (shelf and rise) covers more than 20 percent of the world's sea floor and comprises an area half as large as the total land area of the world (Figure 3). The total worldwide area of the continental shelf available for petroleum development is estimated to amount to 1.4 million square miles (3.6 million km^2). The width of this shelf varies from one coastal area to another in the United States. The shelf can be several hundred miles wide in the Bering Sea off Alaska; in the Gulf of Mexico, it is about 60 miles wide; it extends off the Atlantic coast for approximately 40 miles and narrows to 20 miles or less off the Pacific coast [7].

1.2.2 Exploration and Discovery

The potential of an offshore basin for reserves is estimated by a sequential process involving geological investigation and geophysical and seismic surveys. The potential of a frontier area can be approximated once the following data are known in order of importance: (1) the areal extent and thickness (volume) of closed oil-bearing geological structures (Figure 4); (2) the number of such structures; (3) the history of previous oil or gas production; (4) the geological age of the rocks in the structure; and (5) the depth to the potential reservoir (oil-bearing) rocks [3].

An area in a known petroleum producing basin with large closed structures has a significant potential for hydrocarbons and, if there is an abundance of these structures, the area will continue to attract exploration even after some of the structures are drilled and proved dry. Frontier areas where no previous production has been recorded, however, may support a significant initial exploratory effort, but if no reserves are found, interest may decline rapidly. This is because the investments demanded for geophysical surveys and exploratory drilling are highly speculative--sometimes they pay off but more often there is no return.

Once exploratory drilling occurs, the speculative nature of a new area is rapidly decreased. If paying quantities of oil are found, as defined by a flow rate test (a "drill stem test") of the exploratory well, the area's potential will be sharply upgraded in industry's view and exploratory efforts may accelerate.

If the flow rate test gives uninspiring results, other factors may still indicate promise for the area. These factors, determined by sampling cores in the oil-bearing formations, are the rock's porosity and permeability. If both porosities and permeabilities are high, this indicates that hydrocarbons can be easily extracted if they are present.

After an exploratory hole has been drilled, it will be possible to determine whether marketable oil or gas will be found in commercial amounts. For instance, low viscosity and low sulphur content are more

Figure 3. Mercator projection of the oceans and seas of the world, including the position of the 8,200 feet (2,500 m) depth contour (dashed line) (Source: Reference 6).

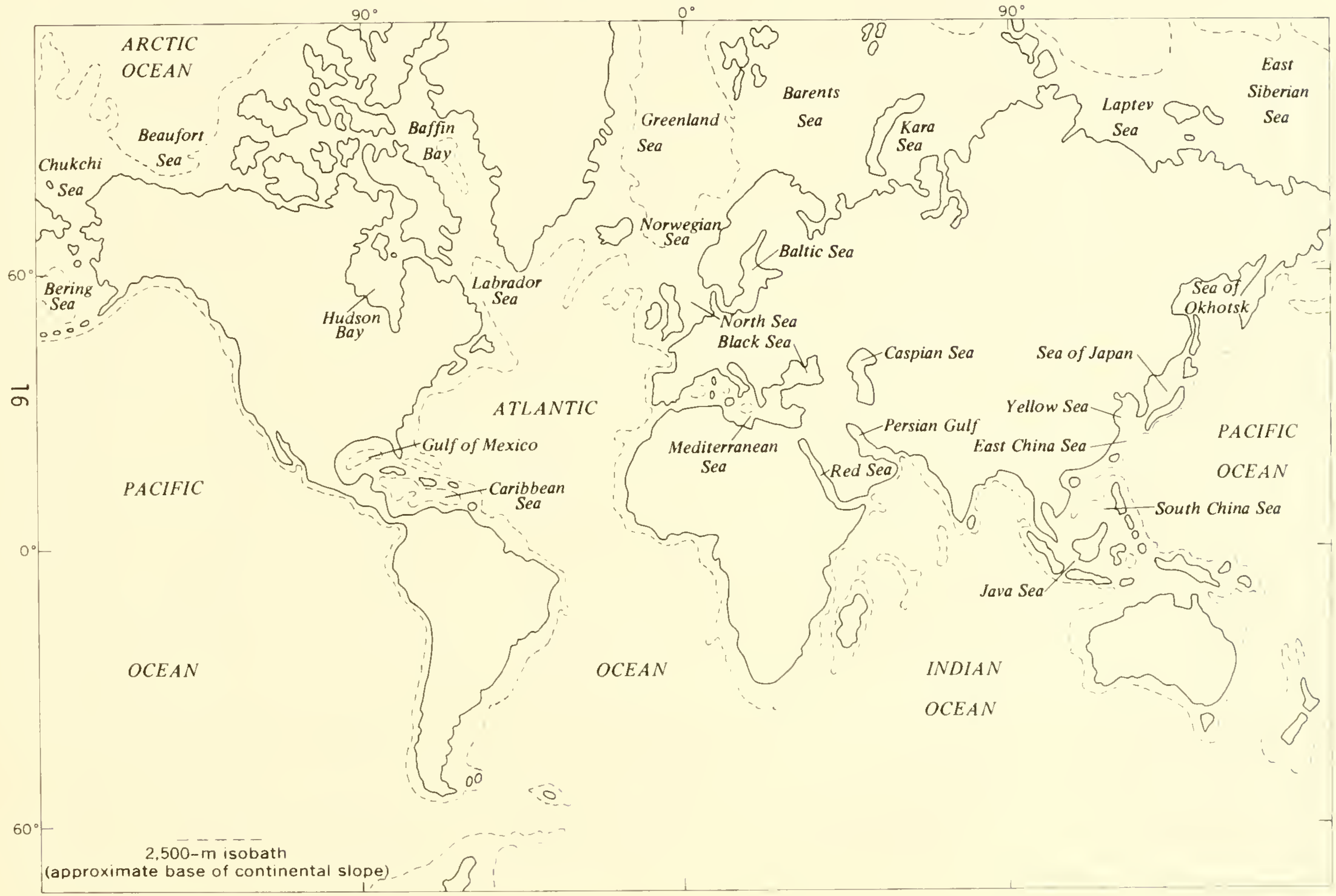
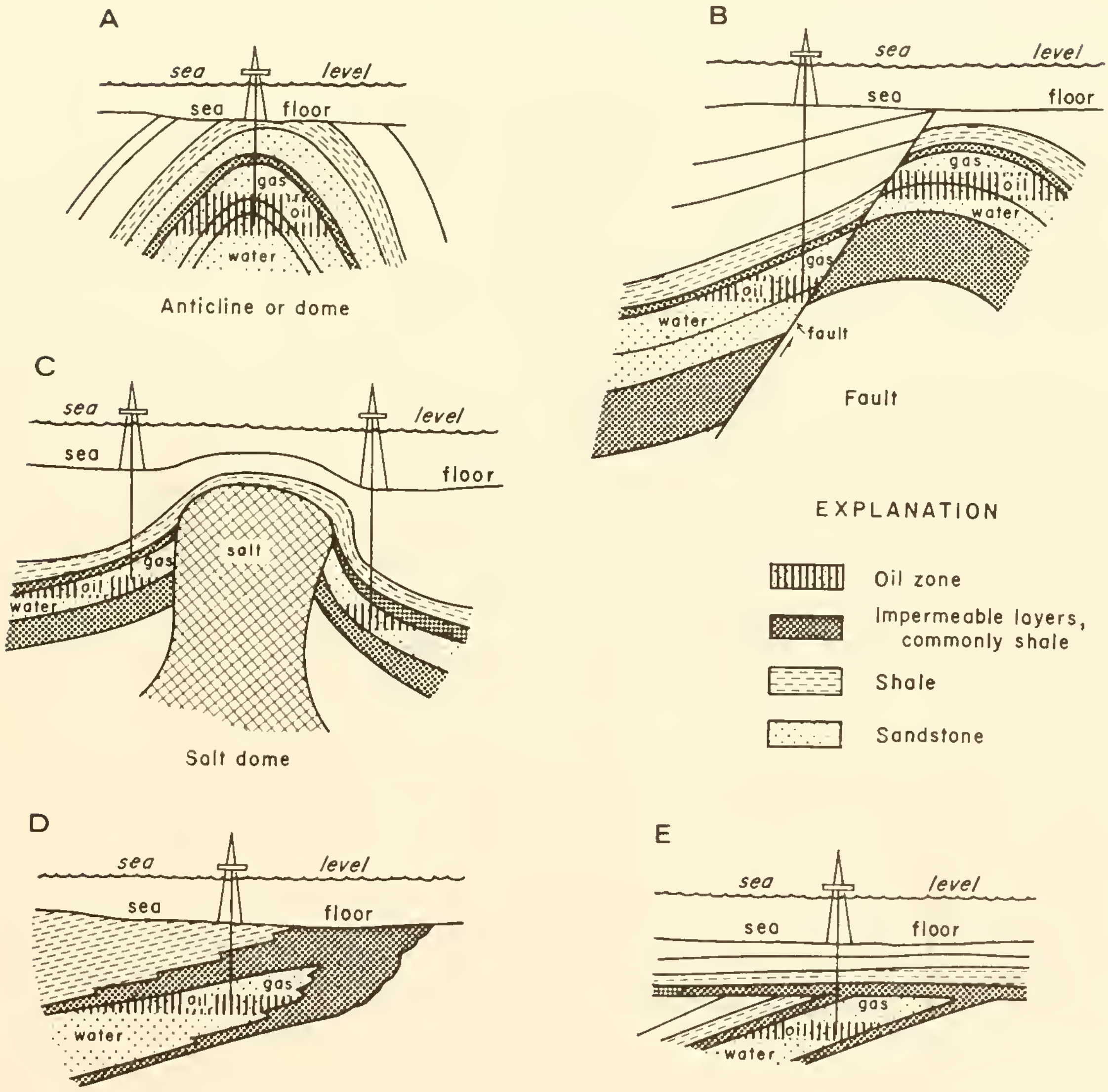


Figure 4. Example of geological traps: Reservoir beds are - (A) arched, (B) faulted, or (C) pierced by shale or salt domes; they also may occur where (D) fossil reefs intrude, or (E) the sediment wedges out at unconformities (Source: Reference 8).



attractive than high viscosity, high sulphur oil. Oil, if found in a remote location, is much more easily transported to a market demand center than gas. (Unless a continuous pipeline can be laid, gas transport requires conversion to a liquid.) In fact, unless large gas reserves are found, it may not be economically worthwhile to proceed with development.

The potential of an area, as defined by these and other factors (e.g., a scarcity of natural gas or a change in prices) is useful in forecasting the amount of exploration activity that is likely to occur in a frontier area.

1.2.3 Geologic Potential of Lease Areas

There are four principal segments of the U.S. Continental Shelf which are present or potential hydrocarbon provinces. These are the Atlantic Shelf, the Gulf of Mexico Shelf, the Pacific Shelf, and the Alaska Shelf. The areas under consideration for leasing on the Atlantic Shelf include Georges Bank, the Baltimore Canyon, the Southeast Georgia Embayment and Blake Plateau [9]. (See Figure 5)

Georges Bank is a structural depression in the continental shelf in the form of a trough approximately 190 miles long and 100 miles wide. The structural deformation consists primarily of high angle faulting, as illustrated in Figure 4, extending into the basement crystalline rocks. It is believed that the central and north portions of the basin have the best likelihood of oil and gas accumulations. The water depth, about 250 to 260 feet, and its close proximity to New England make this area a prime candidate for exploration. A Continental Offshore Stratigraphic Test (COST hole) which will provide more detailed information about sediment characteristics was drilled during the late spring and summer of 1976 off Cape Cod.

The Baltimore Canyon is a trough area which represents a southern continuation of the Georges Bank geologic characteristics. Geophysical surveys indicate the possible existence of a wide range of structures that could trap oil and gas such as faults, reefs, salt domes, and stratigraphic wedge-outs. Geologists believe that any hydrocarbons to be found are likely to be natural gas rather than crude oil. In May, 1976 a C.O.S.T. Hole was completed off New Jersey which will provide further insight into the hydrocarbon potential of the area. The Baltimore Canyon is considered to be the best prospect on the Atlantic Shelf.

The Southeast Georgia Embayment is a relatively shallow basin that lies offshore from South Carolina to Florida in water depths up to 600 feet.

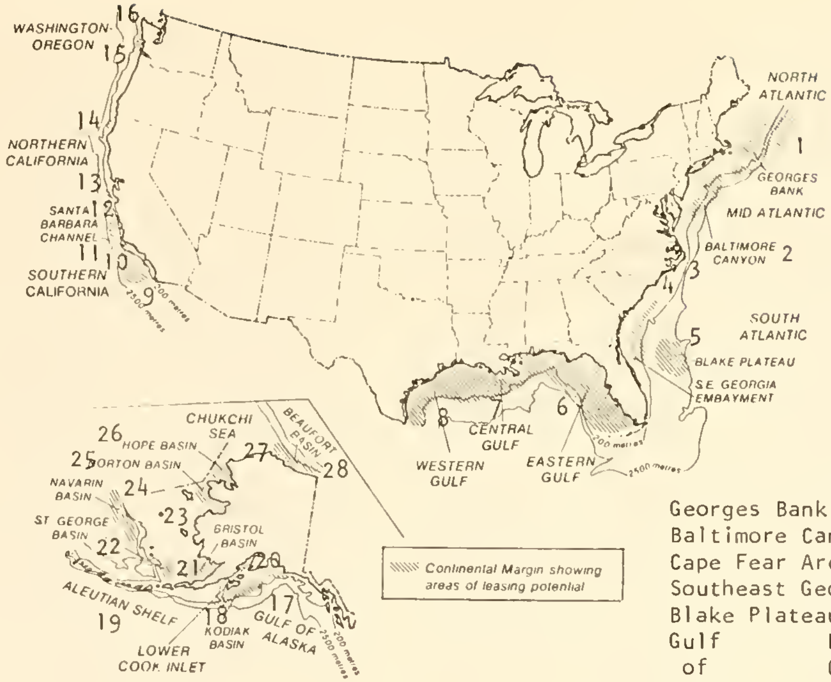


Figure 5. Development status of U.S. offshore basins (Source: Reference 10).

Basin	No.	Regional studies	Reconnaissance seismic	Basin evaluation	Prospect detection seismic	Prospect delineation seismic	Prospect evaluation	Tract evaluation	Bid preparation	Sale	Exploratory drilling	Platform construction	Development drilling completed	Production
Georges Bank trough	1	X	X	X	X	X	X							
Baltimore Canyon trough	2	X	X	X	X	X	X	X	X					
Cape Fear Arch	3	X	X	X										
Southeast Georgia embayment	4	X	X	X										
Blake Plateau trough	5	X	X	X										
Gulf of Mexico Eastern	6	X	X	X	X	X	X	X	X	X	X			
Gulf of Mexico Central	7	X	X	X	X	X	X	X	X	X	X	X	X	X
Gulf of Mexico Western	8	X	X	X	X	X	X	X	X	X	X			
California borderlands	9	X	X	X	X	X	X	X	X	X				
Santa Barbara Channel	10	X	X	X	X	X	X	X	X	X	X	X	X	X
Santa Maria basin	11	X	X	X										
Santa Cruz basin	12	X	X	X										
Arena Bodega basin	13	X	X	X										
Eel River basin	14	X	X	X										
Astoria basin	15	X	X	X										
Olympic basin	16	X	X	X										
Gulf of Alaska	17	X	X	X	X	X	X	X	X	X				
Kodiak shelf	18	X	X	X										
Aleutian shelf	19	X	X	X										
Lower Cook Inlet	20	X	X	X	X									
Bristol basin	21	X	X	X										
St.George basin	22	X	X	X										
Bering shelf	23	X	X	X										
St. Matthew basin	24	X	X											
Norton basin	25	X	X											
Hope basin	26	X	X											
Arctic Offshore basin	27	X	X	X										
Beaufort basin	28	X	X	X										

The Blake Plateau is a deeper "trough" that lies about 140 miles off Georgia and Florida in water depths of between 1,500 feet and 6,000 feet.

The Southeast Georgia Embayment and the Blake Plateau trough are not as favorably looked upon as potential petroleum provinces as other areas because of the relatively thin sequence of sediments in the first case and the deep water conditions in the second.

The Gulf of Mexico is divided into two zones geologically separated into an eastern province with relatively simple geologic structures and a western province of complex structures involving faulting and intrusion of salt beds. Hydrocarbon potential extends from inshore to depths over 1,200 feet.

The Gulf of Mexico has been extensively developed and is the source of 15 to 20 percent of the Nation's petroleum production. At present, the known prime areas of the Gulf have been leased, particularly during the 1970-1975 period. The remaining years of the 1970's will see less exploratory drilling and increased development drilling in the Gulf.

The Pacific Continental Shelf includes the following three sectors: Southern California, central and northern California and Washington-Oregon OCS sectors. The Southern California OCS is a complex geologic structure which includes islands, banks, ridges, submarine canyons and basins. The basins lie in water depths varying between 1,900 feet and 6,200 feet.

The Central-and Northern California OCS is a region that contains six structural basins that are extensions of onshore basins. These basins include from south to north: the Santa Maria, Outer Santa Cruz, Bodega, Point Arena, and Eel River basins.

Oil has already been produced in the onshore Santa Maria basin (609 million barrels to the end of 1973) and the onshore stratigraphic and structural trends are anticipated to continue seaward. For similar reasons, the Eel River basin is believed to be an excellent prospect.

The Washington-Oregon OCS is a region that is part of a trough extending from the Cascade Mountains near the coastline to the continental slope on the west. Although oil and gas seeps and petroliferous muds have been found onshore near the coast, there has been little production. However, limited offshore drilling and geophysical surveying suggest that the offshore presence of suitable sediments exists together with stratigraphic-structural traps.

Alaska is the northern terminus of the mountain system which extends in a continuous belt along North and South America (the American Cordillera). Surrounding Alaska offshore are a number of sedimentary basins that are potential or proved oil and gas provinces. These basins lie in southern Alaska, the Bering Sea, Chukchi Sea and Beaufort Sea.

The Southern Alaska OCS is a basin divided into two potential hydrocarbon provinces, the Gulf of Alaska to the east and the Kodiak to the west. They are similar in terms of sedimentary sequence, but have significantly different structural characteristics. Although most holes drilled in adjacent onshore areas have proven unsuccessful along the Gulf of Alaska, there was one success in 1902, the Katalla oil field, which produced about 150,000 barrels of oil before being abandoned. Moreover, recent seismic surveys have indicated some large scale geologic structures offshore. One structure is almost as large as the Prudhoe Bay formation.

North of the Gulf of Alaska-Kodiak Provinces is the Cook Inlet area consisting of an elongate topographic and structural basin. The offshore Cook Inlet basin represents a seaward extension of a larger onshore petroleum province, a portion of which has been explored and is in production. Through December 1974, the upper Cook Inlet area had produced 600 million barrels of oil and 1.6 trillion cubic feet of gas. Discovered but not yet produced reserves are estimated at 500 million barrels of oil and 4.4 trillion cubic feet of gas [11]. The oil from upper Cook Inlet supports a small refinery at Kenai, Alaska.

The Bering Sea OCS is a composite of several subregions north of the Alaska Peninsula arch. Of the sedimentary basins occurring within or close to the Bering Sea, most promising are Bristol Bay, Norton, Pribilof, St. George, Zhemchum, and Navarin.

The Chukchi Sea OCS is an area off northwestern Alaska that contains two depositional areas of interest, the Hope basin--a broad structural depression in the South Chukchi Sea--and the northern Chukchi Sea basin--an area underlain by geologic features similar to Prudhoe Bay and Naval Petroleum Reserve No.4.

Beaufort Sea OCS extends between Point Barrow and the U.S./Canadian border. The Cretaceous rocks beneath the shelf apparently contain organic-rich shales which may have served as source rocks for the oil and gas deposits found in the younger rocks onshore.

1.2.4 Offshore Oil and Gas Resources

Shown in Table 4 are estimates of the potential amount of undiscovered oil and gas resources on the outer continental shelf. These estimates were recently (1975) prepared by the U.S. Geological Survey after extensive analysis of existing geological and geophysical data. The figures show that beyond the Gulf of Mexico and Southern California (which already possess mature offshore industries), significant hydrocarbon potentials are found only in the Mid Atlantic (Baltimore Canyon Trough), the North Atlantic (Georges Bank Trough), and Alaska. The greatest potential is for Alaska's basins, especially those which are ice-locked most of the year. High anticipated development costs, though, have so far kept interest in the ice-locked basins low.

Table 4. Estimates of "Undiscovered Recoverable" Resources, or Predicted Potential Yields from the Offshore out to Depths of 650 Feet (200 m) (Source: Reference 3)

Number on Figure 5	OCS AREA	Undiscovered Recoverable Resources[1,3] Oil (billion bbls.)		Gas (trillion cu. ft.)	
		SM[2]	5%[3]	SM[2]	5%[3]
1	No. Atlantic	0.9	2.5	4.4	13.1
2	Mid. Atlantic	1.8	4.6	5.3	14.2
4-5	So. Atlantic	0.3	1.3	0.7	2.5
6	Eastern Gulf (MAFLA)	1.0	2.7	1.0	2.8
		(0.5	1.3)	(0.3	1.2)
7-8	Cent. Gulf & So. Texas	3.8	6.4	49.0	93.0
		(0.9	1.9)	(8.7	19.3)
9	So. California	1.1	2.1	1.1	2.1
		(1.2	2.9)	(1.2	2.9)
10	Santa Barbara	1.5	3.0	1.7	3.3
		(0.9	2.1)	(1.1	2.3)
13-14	No. California	0.4	0.8	0.4	0.8
15-16	Washington-Oregon	0.2	0.7	0.3	1.7
20	Cook Inlet	1.2	2.4	2.4	4.5
17-18	Gulf of Alaska	1.5	4.7	5.8	14.0
19	Aleutian Shelf	0.1	0.2	0.1	0.5
21-22	Bristol Basin	0.7	2.4	1.6	5.3
23-26	Bering Sea	2.2	7.0	5.7	15.0
27	Chukchi Sea	6.4	14.5	19.8	38.8
28	Beaufort Sea	3.3	7.6	8.8	19.3

1. Those economic resources not yet discovered which are estimated to exist in favorable geologic environments.

2. Statistical Mean between 95% and 5% probabilities.

3. Additional estimates for deeper areas -- 650 to 8,200 feet (200-2,500 m) -- shown in parentheses for four offshore areas.

The actual amount of recoverable reserves in the offshore frontier areas is unknown, since no actual drilling has taken place at these sites. The varying estimates, as shown above, have been based solely on the interpretation of general geological data. In recent years the estimates have been consistently revised downward. The 1975 USGS estimate indicated that the total undiscovered recoverable OCS oil may be 10 to 49 billion barrels instead of the 65 to 130 billion barrels estimated in 1974 or the 200 to 400 billion barrels previously estimated [7].

To determine the rank order of the U.S. offshore areas, the Department of the Interior, Bureau of Land Management (BLM) solicited information from all concerned parties [13]. Twenty five U.S. oil companies responded to the BLM request, identifying 17 major offshore areas and ranking them based on their view of resource potential and their order of preference. The 17 areas are listed below in rank order, with area number (see Figure 5) and projected year of leasing in parenthesis:

1) Central Gulf of Mexico (7:1976)
2) Gulf of Alaska (Southern Alaska) (17:1976)
3) West Gulf of Mexico (Western Province) (8:1976)
4) Southern California (9:1975)
5) Mid Atlantic (Baltimore Canyon Trough) (2:1976)
6) East Gulf of Mexico (Eastern Province) (6:1977)
7) North Atlantic (Georges Bank Trough) (1:1977)
8) Bristol Bay (21: not scheduled)
9) Beaufort Sea (28:1978 and 1979)
10) Santa Barbara (part of Central-Northern California) (10:1978)
11) Cook Inlet (Southern Alaska) (20:1977 and 1980)
12) Bering Sea (21-26: not on schedule)
13) South Atlantic (Southeast Georgia Embayment and Blake Plateau) (4-5:1977, 1978 and 1979)
14) Chukchi Sea (27:1979)
15) Southern Aleutian Shelf (19:not on schedule)
16) Central-Northern California (11-14:1978 and 1980)
17) Oregon-Washington (15-16:1978 and 1980)

1.2.5 Offshore Production Goals and Potentials

In 1974, the President announced plans to accelerate oil and gas leasing on the Federal Outer Continental Shelf (OCS) on a large scale as a key part of "Project Independence". Seven million acres were offered for sale in 1975 and 1.7 million acres actually leased. Sales have been held for the Southern California, Gulf of Mexico and Mid Atlantic leasing areas. According to the Bureau of Land Management (BLM), Department of the Interior, the goal now is to hold six sales per year (for about 3 million acres per year) through 1980 [7]. The latest OCS planning schedule (January 1977) is shown in Table 5.

The offshore acreage for sale under the schedule in Table 5 is shown in Table 6 along with the scheduled date for final sale in each area. It should be noted that the major constraint on offshore development is not the time to leasing but the time lag associated with development of the technological means necessary to exploit the more remote areas. The acreage of each region that is within the reach of present and near-term technology is also shown in Table 6. If technical impediments are overcome in the next 25 years the capability to explore virtually all U.S. offshore tracts will be available.

Table 5. Proposed OCS Planning Schedule (Source: Reference 12)

August 1977

SALE AREA	1977					1978												1979												1980												1981											
	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
C1 Cook Inlet		N	S																																																		
42 N Atlantic	F		P		N	S																																															
43 South Atlantic Georgia Embayment			F		P		N	S																																													
45 Gulf of Mexico				F		P		N	S																																												
65 Eastern Gulf of Mexico						E		H			F	P		N	S																																						
51 Gulf of Mexico							E		H			F		P		N	S																																				
49 Mid-Atlantic		T						E		H			F			P		N	S																																		
48 Southern California													E		H			F		P		N	S																														
58 Gulf of Mexico			C		D		T							E		H			F		P		N	S																													
54 South Atlantic Blake Plateau		C				D			T									E		H			F		P		N	S																									
Federal/State Beaufort (near shore)			C		D				T											E		H			F			N	S																								
55 Gulf of Alaska										C		D			T										E		H			F		P		N	S																		
62 Gulf of Mexico														C		D			T								E		H			F		P		N	S																
46 Kodiak																													E		H			F		P		N	S														
52 North Atlantic																C		D			T								E		H				F		P		N	S													
53 Central and Northern California				C							D			T																			E		H			F		P		N	S										
60 Cook Inlet																	C		D			T									E				H				F		P		N	S									
56 South Atlantic Georgia Embayment																				C		D			T										E		H			F		P		N	S								
59 Mid-Atlantic																										C		D			T								E		H			F		P		N	S				
66 Gulf of Mexico																												C		D			T							E		H			F		P		N	S			
57 Bering Norton																					C							D			T										E		H					F		P		N	S

C - Call for Nominations
D - Nominations Due
T - Announcement of Tracts
E - Draft Environmental Statement
H - Public Hearing
F - Final Environmental Statement
P - Proposed Notice of Sale
N - Notice of Sale
S - Sale

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Table 6. Offshore Acreage to be Made Available for Leasing by the U.S. Bureau of Land Management, According to January 1977 OCS Planning Schedule (Source: Reference 4)

LOCATION	AVAILABLE OCS ACREAGE (APPROXIMATE)	SCHEDULE DATE OF FINAL AREA SALE	ACREAGE WITHIN REACH OF TECHNOLOGY	
			PRESENT	SHORT TERM (1980-1985)
GULF OF MEXICO (EXCL. FLORIDA)	85 MILLION	9/80	44 MILLION	61 MILLION
FLORIDA MARGIN	95 MILLION	Not on Schedule.	49 MILLION	82 MILLION
ATLANTIC MARGIN	107 MILLION	3/80	19 MILLION	97 MILLION
PACIFIC MARGIN	51 MILLION	11/80	15 MILLION	32 MILLION
ALASKA PACIFIC (EXCL. GULF)	55 MILLION	8/80	36 MILLION	50 MILLION
GULF OF ALASKA	22 MILLION	5/79	16 MILLION	20 MILLION
ALASKA ARTIC MARGIN	178 MILLION	12/79	6 MILLION	6 MILLION
BERING SEA SELF (EXCL. BRISTOL BAY)	217 MILLION	5/80	16 MILLION	16 MILLION
BRISTOL BAY	35 MILLION	Not on Schedule	10 MILLION	16 MILLION
ALEUTIAN SHELVES	45 MILLION	12/80	3 MILLION	29 MILLION
TOTAL	890 MILLION		274 MILLION (31%)	409 MILLION (46%)

1.3 SCHEDULING OF OFFSHORE DEVELOPMENT

Development of offshore oil and gas is a long and complex process. This section discusses development scheduling from two standpoints: first, the six major sequential phases of the development process in which industry and government are both involved, and second, the time constraints placed on industry in meeting the most significant scheduling deadlines.

The ease with which offshore oil and gas fields have been discovered has been found to be related to the degree of geologic knowledge of the area involved. More specifically, the knowledge acquired in developing coastal land hydrocarbon research has accelerated the rate of offshore discovery. More than 80 percent of offshore fields are believed to be either offshore extensions of existing onshore or land-based oil pools, or to have had offshore geology similar to that of the onshore producing area [6]. Certainly prior geologic knowledge speeds the pace of offshore oil and gas field development, although other factors are significant, including technical capability, physical environment, government policies and availability of investment capital.

1.3.1 Geologic Indications

An offshore extension of a producing onshore field takes on the average about 4.4 years to discover, while other offshore areas require approximately fifty percent more time for discovery. Application of our present knowledge to the time frame required for discovery and exploitation of the frontier areas of the United States appears to indicate the following:

1. Excluding environmental constraints, there is strong likelihood that certain Alaskan OCS fields (e.g., Cook Inlet and Beaufort Sea) can be developed in a relatively short time since these areas represent a continuation of onshore fields and geologic conditions.

2. In other Alaskan areas, a number of other variables, including the lack of knowledge of geologic and climatic conditions, could retard development.

3. However, there are no oil fields on the Atlantic coast and the thick geologic sequence of the offshore is not duplicated onshore; hence, the time frame required for

discovery should be much longer than in Alaska. (The Atlantic OCS, for this reason, could be considered unattractive as a potential oil and/or gas province except for offsetting favorable conditions of location and weather.

4. In the intensively explored Gulf of Mexico, the original development was an extension of both onshore fields and the geologic sequence. It has been estimated that significant production from the deeper tracts leased in the last three years will take up to 4 or 5 years.

The decisions on the location, timing and scale of development described above are translated into activities on the offshore and facilities on the onshore. Part 2 identifies and describes these activities and facilities in detail.

1.3.2 Phases of Development

It is convenient to divide the OCS development process into six major sequential phases. Each phase is characterized by the introduction or development of specific industrial projects and activities.

The six phases are (1) pre-exploration, (2) geological and geophysical exploration, (3) exploratory drilling, (4) field development, (5) production, and (6) shut-in of facilities. The development process is analyzed by these phases not only because they are physically different, but also because laws and administrative regulations require that one precede the next. In a mature petroleum province such as the Gulf of Mexico, all of these activities may be occurring simultaneously.

A wide variety of activities, equipment, facilities and projects are required to explore, develop, and place into production oil and gas fields offshore (see Plate 1, following References, for an idealized diagrammatic version of the OCS process).

A flow chart of the major activities involved in the exploration and development of an offshore oil or gas field is shown in Figure 6 along with the six phases of this long and complex process.

1. Pre-exploration: Prior to the initiation of oil and gas prospecting in a frontier area, significant effort is devoted to carefully analyzing available geological and geophysical surveys. The analyses are done by seismic companies under contract to oil and gas

Figure 6. OCS process chart

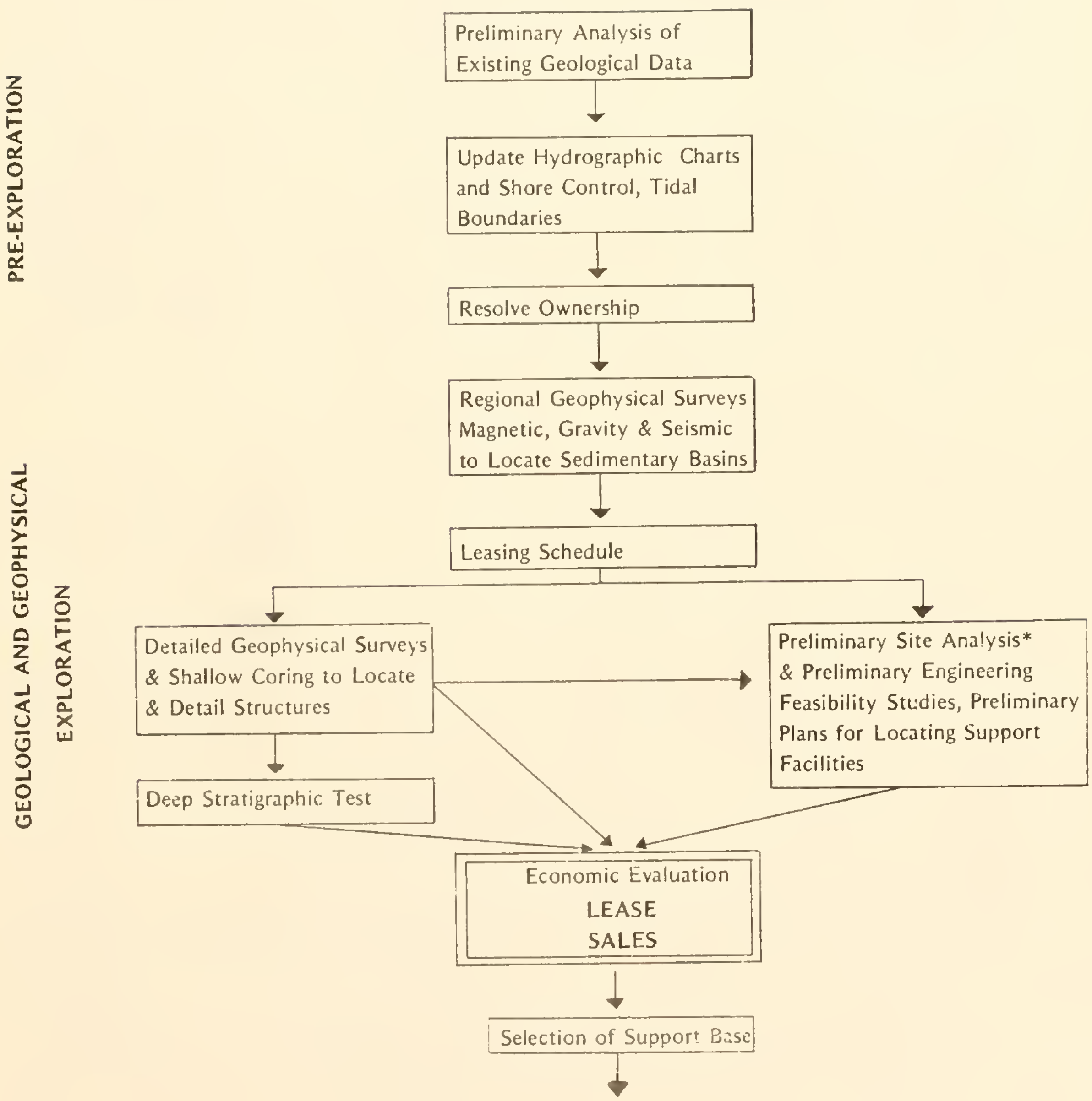
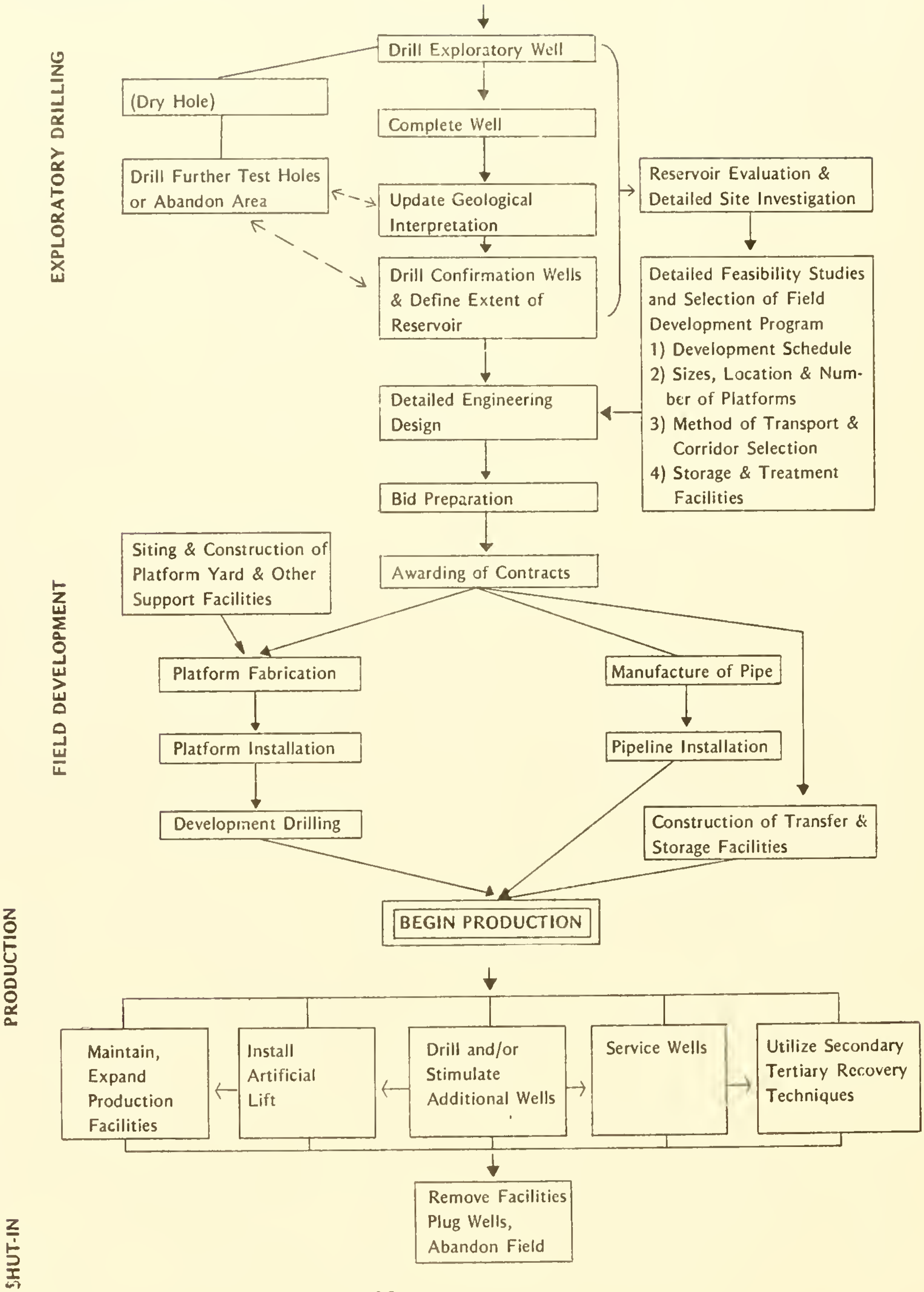


Figure 6 (Continued). OCS process chart



companies. Such analyses identify sedimentary basins and aid in the ranking of frontier areas according to their potential for petroleum.

Once it is determined that a frontier area has hydrocarbon potential it may be necessary, especially in remote areas such as Alaska, to establish survey control networks onshore and to perform hydrographic surveys updating navigation charts. Good surveying control and charts are a prerequisite to reduce the risks to seismic vessels in the search for offshore oil and gas resources. Increased efforts to establish and update horizontal control networks, as well as the operation of hydrographic vessels, are therefore a signal of future OCS oil and gas activities, often followed closely by geophysical vessels searching for petroleum.

Another aspect of the pre-exploration phase that has often been troublesome is resolving ownership disputes between the states and the Federal government. Until the appropriate boundary has been agreed (outer territorial limit off each state involved) and ownership is resolved, it is impossible for the industry to obtain development rights and impossible for the governing body to collect royalties. Often this will require precise tidal boundary surveys at the shoreline correlated with tide state data to determine the low tide line, from which 3-mile (3-league in Texas and Florida Gulf Coast) boundaries can be located.

It is unlikely that the pre-exploration phase would include any major onshore impacts. Indeed, the public is often indifferent to exploration activities and other than company employees and involved Federal workers the only persons who might know that these activities are occurring are fishermen and other maritime interests.

2. <u>Geological and Geophysical Exploration</u>: This phase, like the previous phase, does not usually involve major permanent facilities or major environmental disruption. Work during this phase is based on the current proposed lease schedule worked out between government and industry. From industry recommendations developed in the pre-exploration phase, using regional surveys, the Bureau of Land Management develops an overall leasing schedule which indicates the order in which frontier areas will be offered for lease. Once the schedule is set industry moves its program beyond pre-exploration into detailed geological and geophysical exploration. The companies individually or collectively conduct extensive geophysical surveys and shallow rock coring programs in promising areas to locate and identify geologic structures capable of trapping and holding hydrocarbons.

Where there are large structures, deep test wells (COST) may be drilled by a consortium of companies "off-structure" (away from where hydrocarbons collect) to determine the characteristics of reservoir rocks. The oil and gas companies involved in the effort share the information gained and the multi-million dollar costs involved.

3. Exploratory Drilling: Significant facilities development projects first occur during the exploratory phase. Exploratory drilling activity requires the development of shore support industries, service bases, and marine repair and maintenance facilities. More important, the ground work for other major projects is made during this phase, including obtaining land options and acquiring necessary permits and approvals. Oil and gas companies initiate strategies during this phase that emphasize minimal capital investment.

Exploratory drilling is an operation that begins with relative uncertainty of success, especially in a new province where geologic data are incomplete. Each additional exploratory well drilled and each rock core examined rapidly increases the information base and allows better placement of the next hole.

Teams of geologists carefully examine the records of the seismic, gravity, and magnetic surveys to determine a promising location for the first exploratory well. As drilling proceeds, rock cores are removed and periodically the well is "logged". Well logging is a process by which sonic, electric, and radiation characteristics of the sub-surface rocks are measured, in place, for mapping sub-surface structures.

If the first exploratory well hits what seems to be a commercial find--that is, an encouraging rate of flow of oil or gas--another well will be drilled nearby to confirm the discovery. Success here means a new field has been found and efforts are immediately devoted to estimating the size of the find. A more accurate estimate is developed as appraisal ("step-out") wells are drilled to delineate the horizontal extent of the field and determine the number of wells needed to economically drain the field.

Using the rock cores, well logs, and drill stem tests taken during the exploratory drilling program, petroleum production engineers evaluate the reservoirs to determine the best areas in which to set up permanent oil or gas recovery wells and establish production platforms. Simultaneously surface site investigations are initiated to determine foundation characteristics and subsurface geology of the potential platform locations. Platform locations, then, are determined by the combined efforts of reservoir engineers and engineers who are responsible for designing, fabricating, and installing the platform.

4. Field Development: Field development embraces the rapid implementation of strategies developed during exploratory drilling and earlier phases. (Detailed descriptions of field development and production are discussed in Part 2). During field development, company strategies are refined and reoriented as new and detailed information on the resource comes forth. This reorientation may be expressed in changes in location of onshore supporting facilities. During this phase, the pattern of development becomes crystalized, and it is unlikely to change significantly throughout the productive life of the field.

Field development entails the establishment of a number of major onshore and inshore projects. Possible new projects include fabrication yards, pipelines, natural gas processing plants, pipe-coating yards, transfer systems and onshore storage facilities. Additional onshore support facility development will also be stimulated. The particular pattern of component projects will relate to the resource characteristics and location.

A large find located far from established existing facilities--for example, Prudhoe Bay in Alaska--will stimulate the greatest development "boom". Conversely, a small oil field developed off Georgia would likely utilize products and services transported in from the Gulf of Mexico coast. Refineries in the Caribbean also could be utilized in lieu of refineries in the United States. The ratio of gas to oil in the deposit, and the location of the resource, in relation to existing transportation and processing facilities will also affect the decision as to whether to engage in nearby facilities development.

5. Production: The production phase involves a continuing though lower level of activity but little new strategy. The industrial infrastructure becomes more complex and "mature" during this phase. Production will overlap with exploration for after the initial platform comes on line, exploratory drilling continues in other portions of the basin. Field production patterns are closely intertwined with lease patterns; a large number of companies leasing a field may lead to more production platforms, while if a single company leased an entire field, in theory, only one platform might be required.

The production phase will likely encompass 20 to 30 years. The length of time relates to the size of the field and rate of recovery. In addition, industry is constantly searching for techniques to capture a higher percentage of reservoir hydrocarbons from producing fields. If these efforts are successful, then the life of the field may be expanded--often through "working over" an existing field by applying new or different approaches.

6. Shutdown: As the oil and gas of the specific offshore field approaches exhaustion, it is necessary to start decommissioning specific facilities and installations, i.e., the removing of production platforms. (Only those offshore structures which have been damaged or destroyed by storms have been removed from the Gulf of Mexico.) Refineries would undoubtedly remain but would now have to rely on new sources of supply piped or shipped to the area.

The U.S. Geological Survey normally requires that when a platform is dismantled, all casing or piling is to be cut 15 feet below the sea floor and removed. The well site is then to be dragged to assure removal of any possible obstructions.

Pipelines are generally left in place since the cost of removal is

more than the salvage value of the pipe. However, the connection between the line and the platform is cut at the base of the riser after which the line is capped and sealed.

Tank farms erected for receiving OCS crude oil can obviously be used for storage of oil from other sources but it is more likely that they will be scrapped. Natural gas processing plants would be salvaged or possibly converted to another use.

1.3.3 Time Constraints

Like any business, the oil and gas industry operates for profit. Its schedules, along with other operating strategies, are consistent with optimizing that profit. OCS development activity follows a sequential process in which success during one phase will determine if the next phase should be either initiated, delayed or cancelled. The whole process is very complex and risky.

The time frame for bringing an offshore oil or gas field into production from the time of initiation is conditioned by three principal influences:

1. Geologic factors - involving acquisition of knowledge on the nature of the geologic structure and lithology underlying the area which in turn determines the pace of discovery and the production parameters.

2. Economic criteria - encompassing the myriad of marketing, managing, organization, capital availability and other problems facing an industrial firm considering offshore hydrocarbon development.

3. Regulatory processes and constraints - including all of the Federal and State (and local) reports, operating orders, rules, regulations, standards, and procedures that need to be followed and observed in all phases of offshore operations.

It may take as much as ten years from the time an entrepreneur decides to embark upon an offshore venture to the commencement of production. Even after initial discovery, there will be a protracted period in which appraisal wells are drilled to define the size of the field, productive geologic horizons, outer geographic boundaries, and recoverable reserves. The information derived from appraisal wells is utilized in determining the field development requirements, such as the number of production platforms, the number and location of production wells to be drilled, the size and number of oil tankers or the size and location of pipelines, and the capacity of onshore receiving terminals.

Forty-six examples are given of financial, planning, organizational, management, engineering and general business problems to be overcome--the large capital outlays committing industry to a specific course are concentrated in the latter stages of the schedule as shown below [13]:

Elapsed Time (years)	Activity
0	1. Establishment of initial organization
	2. Determination of purpose
	3. Determination of structural approach of business entity (sole risk or joint venture)
	4. Formation of business entity (corporation, partnership, etc.)
0.5	5. Establishment of requirements (final needs and budget)
	6. Creation of plan
	7. Evaluation of means (to gain competitive position)
	8. Estimation of costs and timing
	9. Framing of objectives
	10. Study of preliminary tasks (economic analysis, infrastructure required, and markets)
	11. Determination of equity positions
	12. Finalization of decisions
1.25	13. Start of negotiations for lease or concession
	14. Contracting of seismic survey (and study of regional geology)
	15. Geophysical surveying of area
	16. On-site seismic surveying of area

17. Detailed seismic surveying of anomalies

18. Evaluation of seismic data

2.6 19. Submission of offer for leases

20. Negotiation of terms

21. (In foreign country, registration of business entity)

22. Selection of base of operations

23. Updating of economic studies

3.7 24. Determination and elimination of roadblocks

25. Start-up of research

26. Acquiring, equipping, and staffing of operating base

27. Installation of communications system

28. Determination of number of exploratory wells to be drilled

4.6 29. Selection and negotiation with drilling contractor and determination of type of rig required

30. Arranging for other services needed for exploratory drilling (support craft, helicopter services, and all types of supplies)

31. Drilling of wells

32. Analysis of drilling results to assess need for additional seismic surveys

33. Review of geological data and estimating of reserves

34. Drilling of confirming or appraisal wells

35. Securing of soil and sea bottom samples

36. Obtaining of oceanographic data

5.1 37. Completion of Exploratory phase (go:no-go decision on field development)

38. Establishment of firm plans and commitments (determination of equipment requirements, platform types, storage and transport systems, reserves, probable production schedule, optimum well program, government regulations, and additional financial needs)

39. Estimation of equipment with long delivery dates

40. Establishment of development drilling program

41. Expansion of staff

42. Selection of engineering and construction firms for design and fabrication of platforms, pipelines, terminals, and other systems and facilities

6.5 43. Design of process system, pipeline, support system, and loading and unloading terminals

44. Installation of platforms, pipelines, and terminals

9.5 45. Installation of drilling systems and drilling and completion of production wells

10.5 46. Commencement of production

PART 2 OCS DEVELOPMENT SYSTEMS

INTRODUCTION AND GUIDE

This part of the report is intended as both an introduction to the specific activities and facilities involved in development and a reference document for the impact assessment which is the ultimate effort of the OCS project. Sections to follow discuss the various aspects of offshore and related onshore technologies that industry may employ in OCS development--techniques currently in use in the United States and those under development.

Offshore oil and gas recovery ventures are financed principally by private industry. The U.S. government both regulates and provides various measures of assistance. Offshore activities are initiated by the OCS industry with geophysical surveys supported by geological studies designed to locate structures and formations that may contain oil and gas deposits. If industry and the Federal government agree that an area has geologic potential, the government may hold a sale and the companies successful in bidding may undertake exploratory drilling to determine the recoverable hydrocarbon reserves.

If sufficient reserves are discovered by exploratory drilling, the operators will embark upon a program of field development to initiate production. A development program will involve not only the drilling of producing wells, but also the installation of platforms, separators to process crude oil and gas offshore, pipelines or vessels to transfer the oil and gas onshore, and onshore tank farms and plants for additional processing. During the production period, additional wells will be drilled, existing wells will be serviced to maintain production, and a variety of techniques will be employed to stimulate lagging output. The oil and gas produced are shipped by pipeline and/or vessels to onshore facilities for refining and marketing.

An understanding of the entire offshore development process is necessary if one is to understand the full range of services, materials, and facilities needed to support offshore activities. The impact of OCS oil and gas activities will fall most heavily upon those onshore communities which become the principal staging areas for offshore operations, and which may become the site of energy transfer and processing facilities. The spectre of these impacts, whether real or imaginary, appears to have become the focus of OCS-related debate in coastal communities adjacent to proposed frontier areas. Officials at the local, county, and state levels are often unsure what effects, positive and negative, they should anticipate. Little information on environmental or economic effects has been available to ease or confirm their concerns.

Organization: Part 2 contains three sections of general discussion followed by a description of 15 specific OCS projects. This general discussion is intended to complement the information on technical aspects of OCS development presented previously in Part 1 by providing information on (1) community acceptance, (2) environmental constraints, and (3) regulatory aspects.

The 15 most significant projects have been selected for detailed description with emphasis on the strategies of OCS development. The decision systems of oil companies and related firms which govern OCS oil and gas recovery must be examined in relation to the six phases of offshore development previously discussed. Each phase is associated with specific offshore activities and needs and with selected onshore support.

The fifteen projects are as follows:

Offshore Development Projects

1. Geophysical survey
2. Exploratory drilling
3. Production drilling
4. Pipelines
5. Offshore mooring and tanker operations

Onshore Development Projects

6. Service bases
7. Marine repair and maintenance
8. General shore support
9. Platform fabrication yards
10. Pipe coating yards
11. Oil storage terminals

Processing Projects

12. Refineries
13. Petrochemical industries
14. Gas processing
15. Liquefied natural gas processing

This choice of projects was made after analysis of known facts about effects of oil and gas recovery on living resources. While concerns about offshore petroleum development have traditionally focused on offshore aspects, the choices above reflect an emphasis on onshore facilities.

The offshore activity and onshore facility projects begin operation at different times in the OCS and related onshore development process as

shown in Figure 7. The chart illustrates the operation life of each process and includes some gradation for times when operations may continue or will continue at a lower scale. This chart illustrates that most planning for facility projects will occur during the last exploratory drilling and early field development phases, after basic characteristics of the field are known and exploitation and support requirements are defined. As shown, each facility follows a sequence which could be clearly observed in frontier areas. These distinct activities will be unrecognizable in an area with established production as the various activities overlap.

Following an introduction,each of the 15 project descriptions presented in Sections 2.2 - 2.4 is divided into 8 standard units:

1. Description
2. Site requirements
3. Construction/Installation
4. Operations
5. Community Effects
6. Effects on Living Resources
7. Regulatory Factors
8. Development Strategy

Introduction: The introduction to each section relates the project to other projects, presents the current situation nationally on the type of projects, and includes a project implementation schedule, or timeline, to show the minimum feasible time from initiation to completion of a project. The time scale is presented as a minimum because average time could be affected by numerous and unpredictable delays along the scale. The schedule is generalized to illustrate major elements of the process; it is recognized that a sponsor may complete hundreds of distinct actions to complete a single element.

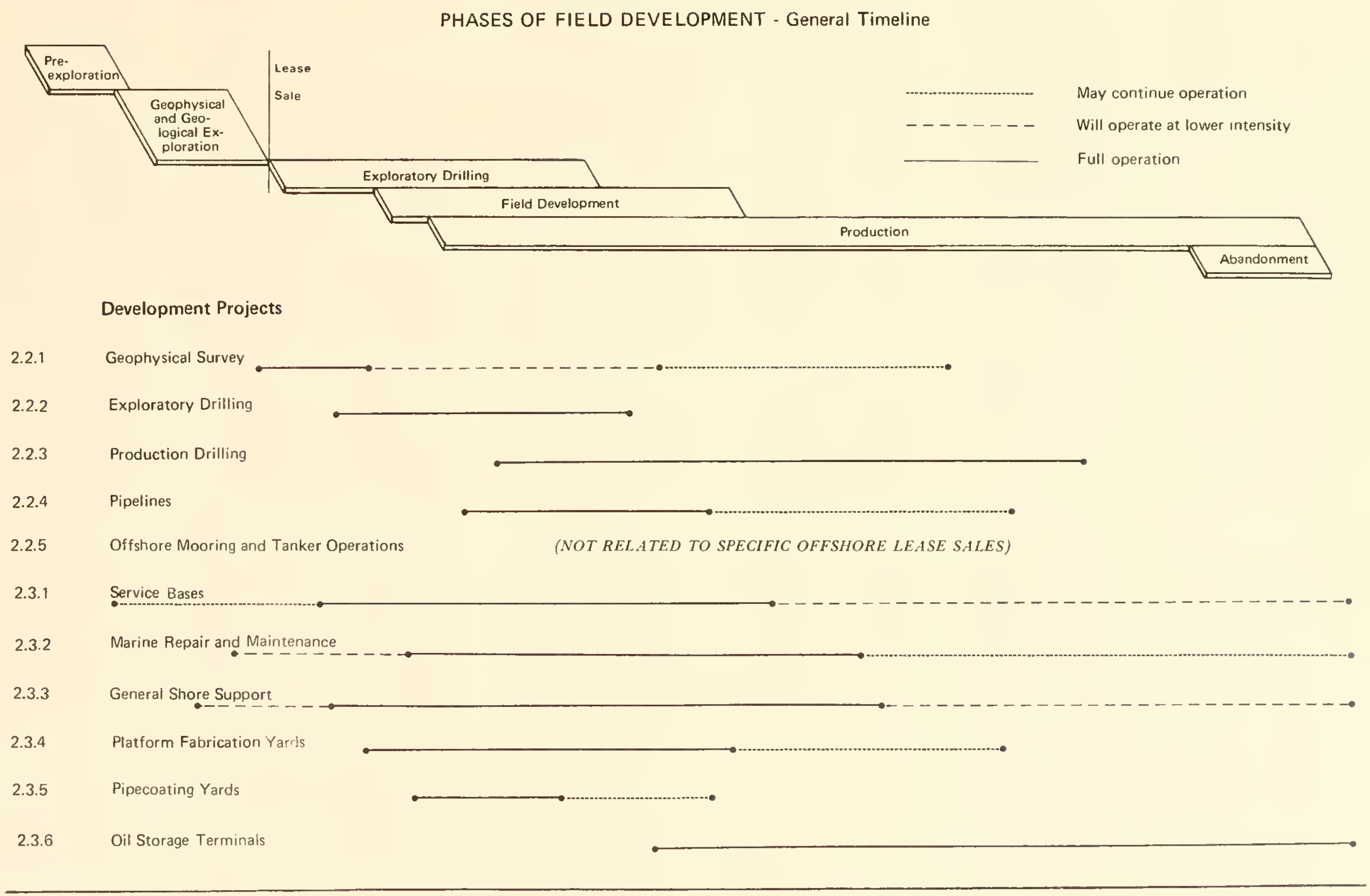
The contents of each unit are briefly reviewed below:

(1) Description: Presents the project and its components in a narrative and graphic format. When finished with a description, a reader should have a clear image of the physical attributes and processes associated with the project.

(2) Site Requirements: Site requirements include important locational considerations. Factors such as waterfront location, access to navigation channel, and access to other transportation elements are important strategic considerations for many of these projects. Where possible, the relative weights of various factors are discussed, as some requirements must be met while others are merely desirable.

(3) Construction/Installation: An important aspect of several projects, such as platform fabrication yards, relates to construction and installation. These concerns are emphasized in this discussion

Figure 7. Relationships of phases of field development to facility project operations.



where construction itself, rather than location, design, or operation has the major potential for impact.

(4) Operations: For a number of the projects, such as onshore support and drilling operations, operation factors--method, duration, and scope--may be more significant than construction and installation.

(5) Community Effects: This topic addresses induced effects of OCS development. A key factor in assessing community effects is employment. Estimates of demands for services, facilities, housing, etc., can be projected from a combination of the increased employment figure, and the project's onsite demands. From these results, estimates can be made of effects on living resources.

(6) Effects on Living Resources: Important environmental strategies related to resource conservation and environmental concerns, especially as they affect living resources--particularly fish and wildlife and their habitats--are discussed (environmental concerns in which the Fish and Wildlife Service is not involved are de-emphasized). As appropriate, conservation-environmental discussions are segmented into four distinct phases of project development: location, design, construction, and operation (including maintenance).

(7) Regulatory Factors: Federal, state, and local regulatory concerns are segmented and described. Discussion of state and local concerns, which vary greatly, is generic. Discussion of Federal regulations is specific and relates back to information in previous sections, primarily the description, site requirements, and environmental factors. The strategy of the sponsor is discussed in terms of avoidable and unavoidable requirements. Strategies to minimize procedural delays are emphasized.

(8) Development Strategy: This section relates the other elements of the presentation to each other. Major strategic considerations are compared and contrasted from the perspective of a decisionmaker in OCS development. The purpose is to enable the reader to understand which constraints are most important and the logic behind the tradeoffs.

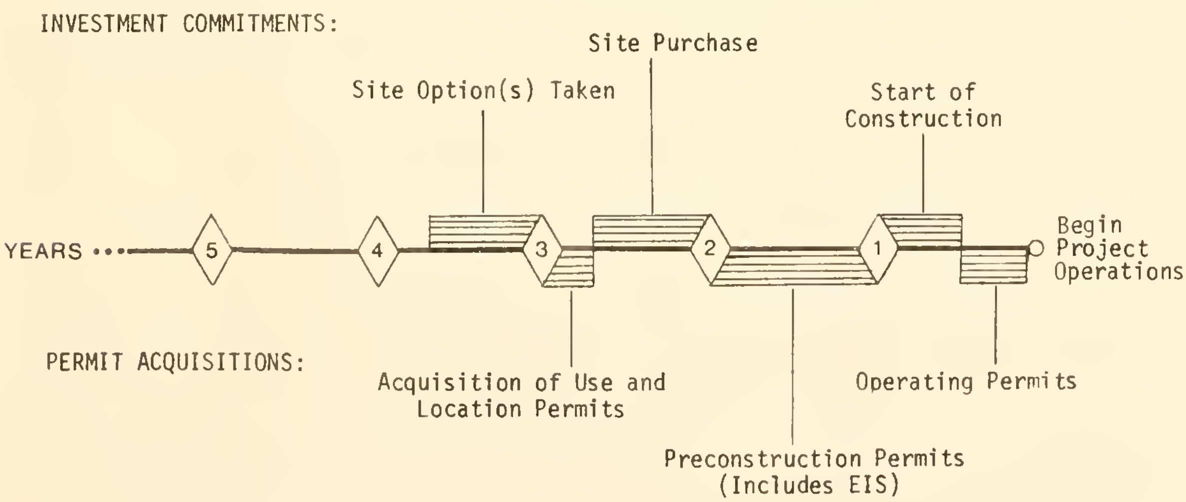
The six major elements, or steps, common to planning and construction aspects of OCS projects are shown on the timeline example chart (Figure 8). An important fact is that variations can occur in the permit sequence, but the other three steps--site option, site purchase, and construction--invariably occur in that order.

The first step is obtaining an option on a potential site. After the option is obtained, use and location permits are sought, primarily through local units of government. These permits may include zoning changes, planning commission approvals, and special use approvals. In addition, certain projects may also require approvals at the state level.

At the completion of this phase, the sponsor has local approval to proceed with his concept and can purchase the property. After the property is purchased, a series of preconstruction permits must be obtained; these incorporate most of the major Federal requirements such as environmental impact statements and dredge and fill permits in selected cases.

After the permits are obtained, construction is initiated. During the construction phase, operating permits that may not have been obtained earlier, are sought; however, any permits that are considered difficult to obtain are likely to have been sought prior to construction while the investment was still minimal. After construction is completed the facility can then begin functioning in the OCS oil and gas process.

Figure 8. Project implementation schedule (sample).



2.1 FACTORS OF INFLUENCE

In the implementation of an OCS development system there are a number of important spheres of interest. In this section we discuss four of these. The first three--community (indirect) effects, living resources, and regulatory factors--are to be covered in detail in separate reports of the OCS project series (Volumes 2, 3 and 4). They are covered here only to the extent necessary to provide a background for the descriptions of specific OCS projects. The section concludes with a discussion of industry decision factors.

2.1.1 Community Factors--Indirect Effects

The key factor in assessing community effects is employment. The total number of individuals to be employed is the summation of direct employment (the facility project under consideration), indirect employment (working for other companies that support the facility project), and induced employment (employment generated in other sectors of the economy such as school teachers). (Indirect and induced employment are addressed in detail in Volume 3 on community effects.)

Critical matters to consider in employment are: (1) the different requirements of construction and operation employment, (2) the interrelated timing of employment opportunities for individual projects, and (3) the percentage of employees who are new regional residents. For many projects, such as refineries and pipelines, construction and installation require large labor forces, while operating employment is much lower. For other facilities, such as platform fabrication yards, the operating force may exceed the construction labor force.

During construction and operation, a percentage of employees will also be new residents to the area. Those who are current residents will not require substantial changes in local services, while new residents will require service from the public and private sectors that had not been demanded previously. The number of secondary and induced employees needed because of the new direct employment is difficult to predict. A number of factors affect the relationship to direct employment; the size of the community before the project, income of workers, length of construction phase, and distance from metropolitan areas are the most important. As a general rule, from 0.3 to 0.9 secondary workers are needed for each new construction worker, and from 1.1 to 2.3 secondary workers for each permanent employee [6], while induced employment on OCS-related industry is projected to be at least 1.2 for all direct and indirect workers.

Induced effects are a major consideration. Communities concerned with industrial development options tend to view new plant payrolls and property taxes as an added economic benefit, and local commercial interests sense the potential for increased profits. But the commitment of coastal lands for heavy industry sites may engender a wide variety of impacts that extend considerably beyond the direct, localized, impacts of the plant. Certainly, new residents employed by a new OCS facility will generate a demand that may require expansion in the public sector for utilities and services such as sewage treatment and water supply, and may induce housing projects, shopping centers and other community development in the private sector. And the facility may attract more industry. All this development has a potential for impact on living resources. In addition, costs to the community for more streets, police and fire protection, schools and other essential services, may be greater than the direct costs of the plant itself, requiring that planning decisions relating to industrial siting must include the development they will induce.

2.1.2 Effects on Living Resources

Resource conservation and environmental impacts may be severe for onshore facilities. Those concerns relating to fish and wildlife and their habitats are most significant for large, heavy impact OCS projects, i.e., exploration and production drilling, platform fabrication yards, pipelines, oil refineries, and petrochemical industries. Effects on living resources may arise from decisions made in each of four distinct phases of OCS projects: location, design, construction, and operation (including maintenance). The following considers only those factors having a major influence on fish and wildlife and excludes marginal factors of importance to them even though they may be important otherwise (e.g., air pollution).

Location: Waterfront locations of facilities may require dredge and spoil disposal which can lead to adverse ecologic effects, such as: (1) turbidity; (2) eutrophication; (3) toxification; (4) basin shoaling and oxygen depletion; (5) wetlands loss; and (6) benthic habitat degradation. Other major consequences of the waterfront location include: (1) shoreline alteration from bulkheading; (2) preemption of land for filling; (3) disruption and degradation of wetlands and other vital areas. Solutions can be effected through taking special care to reduce effects on terrestrial wildlife, endangered species habitats, and aquatic ecosystems. Where waterfront locations are not required for the facilities the use of upland areas will preclude many of these problems and will retain waterfront sites for uses which require that type of access.

Design: The high potential for adverse aquatic impacts of the waterfront location requires that maximum care be taken in design of the facility. Solutions include provisions for: (1) maintaining the natural shoreline; (2) minimizing dredging; (3) arranging proper disposal of

spoil; (4) avoiding wetlands; (5) reducing problems of runoff discharge through proper watershed management and (6) provision of buffer strips.

Facilities handling petroleum will cause concern for: (1) avoidance of oil spills; (2) avoidance of discharge of pollutants and (3) minimizing subsurface water withdrawal. Also the large acreages of shorelands require that special care be given to reducing effects on terrestrial wildlife, endangered species habitats, and the aquatic ecosystem. Elevations below the 100-year flood level are undesirable for OCS facilities in coastal or floodplain areas.

Construction: During site preparation there can be a number of serious effects, direct and indirect. Solutions can be found through (1) minimizing the alteration of water systems; (2) preventing the erosion of soil; and (3) eliminating the discharge of toxic or deleterious substances. Excavation and filling of areas near wetlands must be done in such a manner that sediments do not enter the wetlands ecosystems. Revegetation of disturbed areas must be accomplished as soon as possible to reduce erosion.

Operation: The major environmental problem of OCS projects in operation generally will be in meeting pollutant discharge standards on waste disposal and runoff water. Solutions are through proper application of Federal and state pollution controls. Frequent maintenance dredging of an access channel may cause serious problems, particularly in the availability of suitable disposal sites for spoil. Therefore, location and design standards are important. Spill containment precautions should be developed.

Sponsor Strategy: Normally, the sponsor's environmental concerns are related to the governmental regulatory controls that must be met and to public reaction to environmental and other impacts. Extensive administrative and litigative delays can result if either environmental assessment studies are weak or if the mitigation plan is inadequate.

Normally, location problems of the facility are by far the most important ones affecting fish and wildlife resources, and the one that the sponsor will give the most effort to solving. Next in order will be designing the facility to avoid shoreline disturbances, particularly of wetlands. Third and fourth in priority will be requirements for construction and operation. However, depending upon the locale and other specifics, the priority of the above may change dramatically. In any event, concern for the fish and wildlife resource is only one constraint in the whole development sphere and often there are strong pressures to subjugate such concern to economic and social factors or to other environmental aspects (e.g., air quality, scenic impacts).

2.1.3 Regulatory Factors

Onshore projects and facilities for offshore oil and gas development must meet location, design, and operating conditions imposed under a broad array of state, local, and Federal laws and regulations. The Fish and Wildlife Service participates in two distinct Federal program areas with implications for OCS-related onshore facilities: (1) general, under a variety of Federal laws applying to onshore and nearshore development; and, (2) specific, under the Outer Continental Shelf Land Act and the lease tract selection, evaluation, and management process authorized. (Table 7)

First, through the Fish and Wildlife Coordination Act, the Service is advisory to other Federal agencies in direct regulation or management of certain development activities onshore and in the nearshore area.* In this first subject area, the Federal regulatory role as it affects privately owned land is concurrent with state and local programs, often in the same subject areas.

Second, in the Outer Continental Shelf leasing program the Service contributes in suggesting or reviewing stipulations for lease sales which include conditions for offshore development. Because leasing involves the sale of Federal interests to private parties in an area of exclusive Federal jurisdiction, the Bureau of Land Management (BLM) prepares final decisions on leasing and the Geological Survey (USGS) takes similar actions for exploration, development, and production management.

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* Fish and Wildlife Coordination Act, 16 U.S.C. 661-667e; 48 Stat. 401, as amended; and the related provisions of the National Environmental Policy Act of 1969, 42 U.S.C. 4321-4347.

Table 7. Federal Laws Relevant to U.S. Fish and Wildlife Service Responsibilities

Federal Laws
Airport and Airway Development Act, as amended, 49 U.S.C. Section 170 to 1703, 1711 to 1727.
Anadromous Fish Conservation Act, as amended, 16 U.S.C. Sections 757a to 757F.
Coastal Zone Management Act of 1972, as amended, 16 U.S.C. Section 1451 to 1464.
Deepwater Port Act of 1974, 33 U.S.C. Section 1501 to 1524; 43 U.S.C. Section 1333.
Department of Transportation and Related Acts, as amended, 49 U.S.C. Sections 1652 to 1657, 305a; 14 U.S.C. Section 92 note; 20 U.S.C. Section 241 note.
Endangered Species Conservation Act of 1969, 16 U.S.C. Sections 668aa to 668cc-6.
Estuary Protection Act, See 16 U.S.C. Sections 1451 to 1464.
Federal Power Act, as amended, 16 U.S.C. Section 791a et. seq.
Federal Water Pollution Control Act, as amended, 33 U.S.C. Section 1151 et. seq.
Fish and Wildlife Coordination Act, as amended, 16 U.S.C. Sections 661 to 666c.
Historic Sites, Buildings and Antiquities Act, as amended, 16 U.S.C. Sections 461 to 467.
Interstate Land Sales Full Disclosure Act, as amended, 15 U.S.C. Sections 1701 to 1720.
Marine Protection, Research, and Sanctuaries Act of 1972, 13 U.S.C. Sections 1401, 1402, 1411 to 1421, 1441 to 1444; 16 U.S.C. Sections 1431 to 1434.
Migratory Bird Conservation Act, as amended, 16 U.S.C. Sections 715 to 715s.
Migratory Bird Hunting Stamp Act, as amended, 16 U.S.C. Sections 718 to 718h.
Migratory Bird Treaty Act, as amended, 16 U.S.C. Sections 668aa, 668bb, 668cc-1, 703 to 708, 709a, 710, 711.
National Wildlife Refuge System Administration Act of 1966, 16 U.S.C.Sections 668dd, 668ee.
Outdoor Recreation Resources Review Act, as amended, 16 U.S.C. Section 17k note.
Outer Continental Shelf Lands Act as amended, 10 U.S.C. Sections 7421 to 7426, 7428 to 7438; 43 U.S.C. Sections 1331 note, 1331 to 1343.
Protection of Navigable Waters (Rivers and Harbors Appropriation Act of 1899), 33 U.S.C. Section 401, 403, 404, 406, 407, 408, 409, 411 to 415, 418, 502, 549, 686, 687. See: U.S.C. Section 725a(v)(14).
Submerged Lands Act, 43 U.S.C. Sections 1301 to 1303, 1311 to 1315; See: 10 U.S.C. Sections 7421 to 7426, 7428 to 7438.
Watershed Protection and Flood Prevention Act, as amended, 16 U.S.C. Sections 1001 to 1005.
Wetlands Act of 1961, 16 U.S.C. Sections 715 k-3 to 715 k-5.
Wild and Scenic Rivers Act, as amended, 16 U.S.C. Sections 1271 to 1287.
Wilderness Act, 16 U.S.C. Sections 1131 to 1136.

In addition to these two primary categories, Federal highway programs and most pipeline decisions also involve the FWS in an advisory role. Under the Coordination Act, the Service may, upon request, provide advice to states in certain situations where their development activities require Federal permits or certifications.

Site locations in nearshore and onshore areas are significantly affected by state and local laws and regulations. The interaction of land and water requirements for a site, and the size of the site used for storage and industrial activity govern the extent of applications to state and local governments for zoning and related permits. Permits or approvals required before starting construction typically include one or more of the following:

- zoning use designation
- permission to subdivide land ownership
- certification of flood proofing and location outside highest flood hazard area
- wetlands or critical areas conservation or impact mitigation
- site alteration assurances to guard against erosion or drainage alterations
- dredge and fill permit (state)

This report will not discuss these programs, but excellent secondary sources exist. [Note: For example: HUD, Statutory Land Use Control Enabling Authority in the Fifty States, September 1976, U.S. GPO/HUD-FIA-179.] Permission under many of these types of regulations may be denied as a matter of state (or local) policy at any point in a sponsor's planning process before construction begins. Because of this, local assurances such as zoning approval are often sought well before applications for Federal permits are submitted.

In addition to development-related permits, operation of a facility may require both Federal and state permits. The most common categories include pollutant discharge and maintenance dredging.

An important consideration in the formal regulatory process is coordination of state and Federal programs. Corps of Engineers' regulations require state disposition of related issues before issuance of Corps dredge and fill permits. [Note: Regulations published July 25, 1975, Volume 40 of the Federal Register, pages 31320 et seq.]

The Coastal Zone Management Act of 1972 requires greater coordination between state and Federal agencies in states which have approved Coastal Zone Management plans.

Faced with the economic risks and the complexity of the regulatory process and equally demanding capital financing requirements, a facility

sponsor must make several crucial decisions in attempting to locate an onshore OCS-related development facility. Subtle issues in the regulatory enforcement process may affect the short and long-term potential a site has for the sponsor's needs. For instance, the existence of a state "large-scale-development" review program may cause delays in initial site approvals, but may provide greater security than simple local zoning approvals to the life of a development. Location in an existing industrial area may eliminate many local approvals because zoning would already permit industry. But land prices for the site may be higher because of the greater simplicity or attractiveness of the site. The decision becomes primarily one of capital availability and carrying costs (primarily interest on borrowed money) rather than site characteristics.

Information requirements for different public approval programs may differ significantly. Sequential presentations with each specifically tailored to one agency to get one approval have often been more effective than blanket or overview reports that might arouse general interest in the details of a project. The environmental impact assessment process has changed traditional approaches to this problem, as described in Volumes 2, 3, and 4 in this series, each of which deals extensively with the sorts of information commonly presented and with important concepts, definitions, and ecologic factors that come up in either the tailored or general information approach.

Pre-leasing and exploratory drilling reviews typically proceed independently of sponsor attempts to locate suitable onshore sites for related development. During the field development phase, onshore facilities are also being sited with applications to the Corps of Engineers, who are advised by district and regional representatives of FWS.

2.1.4 Industry Decision Factors

The offshore industry's decision process is aimed at finding the optimum balance among a complex set of tradeoffs. The tradeoff elements include technical, environmental, regulatory, community, and direct economic factors. This section focuses on the principal factors that affect the whole OCS development decision process.

Economic Constraints: Profits from OCS development depend on the costs of recovery, which are a function of the difficulties of exploration and development, which in turn, are dependent upon both the location of the frontier area and the technical difficulties of operating the area in which drilling is planned.

If the potential for payoff is doubtful and a company's rate of profit is unfavorable, it is extremely risky for the company to engage heavily in exploration activities. If a marginally commercial discovery

is made, the company might have a problem generating capital to develop the field, as well as the considerable time lags before the field would be on-line generating an incoming cash flow. In a remote and hostile area, such as Alaska, the huge front-end investment costs and the estimated 5 to 8 year span between discovery and production may exclude all but the largest and most wealthy of oil companies--and they create joint ventures to spread the costs and risks in major development.

To assess the risk of investing in offshore oil resources from an industry point of view, the following major factors need to be considered:

1. the physical costs of installing and operating producing wells and facilities for various water depths and climatic conditions;

2. the cost of exploratory dry holes (up to $1 million each) that must be paid for by production from successful wells;

3. nonphysical costs such as royalties, taxes, bonuses, and the cost of capital including required return on investments;

4. size of the oil/gas field, physical characteristics and productive capacities for a single producing facility;

5. the timing of technical capability for operating at various water depths and climatic conditions, assuming that the current state of the art precludes operations under ice conditions or in depths in excess of 3,300 feet (1,000 m);

6. estimated costs of other fuels with which offshore petroleum must compete;

7. marketing costs and considerations (e.g., need to maintain market leadership in a given area).

Offshore oil development can be economical under a wide range of reservoir size, water depth, and climate conditions. Economic feasibility rapidly diminishes as reservoirs become smaller, water deeper and climatic conditions more severe. It must be realized that the petroleum industry does not profit from exploring for oil; its profits come from production and marketing. Geological and geophysical surveys and exploratory drilling operations, though necessary to assure the industry's long-term survival, are regarded as speculative ventures by the industry. When industry's profits fall, exploration expenditures are curtailed and emphasis is placed on developing already discovered reserves. This

represents a more conservative investment, since the economic and technical feasibility of developing known reserves can be fairly accurately determined, and only those projects yielding an acceptable rate of return will be initiated.

The decision to proceed or not to proceed with offshore exploration and development of OCS oil and gas is an investment decision based on a company's estimate of the costs involved in relation to the revenue generated and the ultimate return on investment. Operations offshore are considerably more expensive than onshore and the investment risk and the return must be higher than what usually has been considered adequate for onshore operations.

The massive capital cost associated with establishing an offshore production field weighs heavily upon the decision to proceed with OCS development. As operations have moved into deeper waters, more hostile environments, and more remote areas, the capital cost of the facilities required to bring a field into production have climbed into the hundreds of millions of dollars. Development of Phillips Petroleum's Ekofisk field in the North Sea has cost approximately $4.5 billion. As a result of such high costs, British operators now estimate that fields in the North Sea must yield at least 200,000 barrels of oil per day to be economically feasible. Support of the heavy "front-end" capital investments required in frontier areas, especially the remote areas of Alaska, will require production in excess of 100,000 barrels per day.

Other important financial factors considered by the industry are the cost of money, i.e., the prevailing interest rate to corporate borrowers, and the considerable time involved between investment and production. Time lags are in actuality money costs, because the investor foregoes the opportunity of gaining a return while his money is tied up in non-productive investment. When the time lag between beginning the development of an offshore field and initiating production is long, as it will be in the more remote areas of Alaska, only fields with substantial reserves will attract investors.

The overall investment of capital for developing offshore resources both here and abroad is anticipated to continue at a rather vigorous pace in the next few years. One estimate, predicts that in the years 1975-1980, expenditures for exploration in North America will amount to $15 billion (85 percent of which will be in the United States), while development costs to produce the discovered oil and gas fields will amount to over $21 billion [14].

A most troublesome economic factor for the U.S. oil and gas industry in the last several years has been inflation. The industry has had problems getting a reliable prediction of what a project will cost when finally completed. Costs on many projects have escalated drastically from inception to final completion in the 1970's.

The costs of exploratory and development/production drilling and other services incidental to offshore exploitation have risen particularly steeply. For example, a jackup rig which cost $8-9 million in 1971, cost close to $20 million by 1976.

Market trends are very important. The current and future price of oil and gas, their demand outlook, and the cost and availability of petroleum from alternative sources all have significant influence on the decision to proceed with development. During the past few years, the above factors have become somewhat unpredictable due to the instabilities in the world market. For example, since Middle East production costs are a fraction of the U.S. production costs offshore, these nations have a great deal of flexibility in manipulating the market, such as increasing production and simultaneously lowering oil prices, which could undermine investment in U.S. offshore development.

The location of a promising field, and the distance to the desired market is important. If oil and gas are discovered in a frontier area, they must be transported to a refining center to be processed and readied for distribution. A field in close proximity to a refining center will probably require a much lower threshold of reserves to make development economically feasible. Oil can be transported by tanker from remote areas, but the threshold of reserves required to encourage an investment for the construction of oil storage and transfer systems or a pipeline to shore may be quite large.

Technical Constraints: The difficulty of recovery of oil and gas resources is a function of the hardship and complexity of exploration and development. This in turn depends upon both the location of the frontier area in which drilling is planned and its characteristics.

A major factor which affects the cost of exploration and feasibility of development of the frontier area is the degree of remoteness from sources of supply for steel, pipe, concrete, platform jackets, and other heavy industrial goods. All of the Alaskan frontier areas are remote from the source of supplies, especially those basins north of the Aleutians. Here, transportation costs add significantly to the cost of development. In contrast, the U.S. Atlantic frontier areas are all relatively near supply areas.

Another important locational constraint affecting the difficulty of developing an offshore field is the distance between the offshore oil or gas field and the shore. The cost of transporting men, fuel, materials, and drilling equipment is a function of distance travelled. In storm-swept areas such as the Gulf of Alaska, Bristol Bay, and the Bering Sea, distance is especially critical, because of weather changes during the long trip; for example a supply vessel can depart in good weather but encounter adverse conditions before reaching the platform and off-loading. Supply may be impossible for many days while costly drilling rigs or platforms stand idle.

Depending on the severity of conditions--wind, waves, currents, tides, storms, earthquakes, temperatures, and ice--the cost of offshore development can escalate to almost five times the cost incurred under ideal conditions (few storms, light winds, mild tides, no ice) as found in the Persian Gulf and Mediterranean Sea. Ice imposes the most severe limitations, and thus the greatest increase in cost. Transport through sea ice is nearly impossible; the shearing and crushing effects of sheet ice on fixed structures impose severe design criteria on platforms; and it may be nearly impossible to construct a pipeline to shore that will not be ruptured by moving ice floe pressure ridges.

A third factor affecting development is the geological character of the ocean bottom which must support the production platform. Areas of difficulty are soft sediments, mud slumps, sand waves, rock outcrops, steep slopes, and faults. If technical solutions are not available, development is precluded on such OCS areas.

A fourth factor is water depth. The difficulty of either exploration or production is compounded by deep water. This is reflected in the complexity of drill rigs required for deeper water (semi-submersibles) as opposed to those required for shallower (less than 350 feet) waters (jack-up rigs). Development costs are as heavily dependent upon water depth as exploration costs or more so. For example, standard platforms ("fixed" type) increase in cost as a function of the square of water depth. In order to maintain a stable base-to-height ratio in deeper waters, platforms increase exponentially in size and in number of joints. Therefore, the amount of material and labor required also increases exponentially.

Table 8A compares drilling expenses for a base case of the Gulf of Mexico with other combinations of conditions of depth, climate, and seismicity. Although construction costs have risen sharply in the past two years due to inflationary pressures (25 to 35 percent) the relationships expressed by the index are valid. As shown in Table 8B development and production expenditures would likewise increase with increased depth and more severe climatic conditions.

Except for the areas north of the Alaskan Peninsula, industry engineers believe they have the technical know-how and the exploration production equipment, expertise, and experience to undertake development on most of the U.S. Outer Continental Shelf. However, severe storms and seismic risks pose a grave threat to offshore development in Alaskan Artic waters and engineering design improvements of current equipment and consideration of new systems will undoubtedly be required.

Jack-up rigs will probably be used on the east coast offshore up to depths of 300 to 350 feet. Semi-submersibles will be used for exploratory drilling beyond that to a depth of 1,500 feet.

Projected water depth drilling and production capabilities for the various areas to be leased are shown in Table 9.

Table 8. Offshore Exploration Drilling Expenditure Index Comparing Gulf of Mexico (Moderate Climate, 650-Foot Depth) to Other Areas. 1.0 Equals $2.7 Million Per Well in 1974 Dollars (Source: Reference 15)

Water Depth Feet	(Meters)	Drilling Expenditure Index: Climatic Conditions: Mild	Moderate[1]	Severe[2]	Ice Laden: 75%[3]	100%[4]
		A. Exploratory Drilling				
650	200	0.8	1.0	1.8	2.3	4.6
1,650	500	1.0	1.3	2.1	2.8	5.4
3,250	1,000	2.5	2.8	3.6	4.3	6.4
		B. Development and Production				
650	200	0.9	1.0	2.8	Unknown but estimated to be substantially greater than "Severe" case.	
1,000	300	---	---	6.2		
1.650	500	2.7	3.0	---		
3,250	1,000	4.3	4.8	10.2		

[1]Moderate Climate - Gulf of Mexico, South Atlantic, and California

[2]Severe Climate - North Atlantic and Gulf of Alaska

[3]75% Ice Laden - Bristol Bay

[4]100% Ice Laden - Chukchi Sea and Beaufort Sea

[5]Climatic conditions include earthquakes.

Table 9. Present and Future Water Depth and Earliest Dates for Exploration Drilling and Production for United States Outer Continental Shelf Areas (Source: Reference 15)

Area/Province	Maximum Water Depth Capabilities: Exploration Drilling*	Maximum Water Depth Capabilities: Production	Earliest Date: Exploration Drilling	Earliest Date: Production†
1. North Atlantic	At present, jack-ups 300 - 350 feet. Drillships and semi-submersibles 1,000 - 1,500 feet. Dynamically positioned drillships 2,500 - 3,000 feet. In the future, forecast capabilities up to 6,000 feet by 1980	At present, fixed platforms 600 feet. Under water completions (UWC) 1,200 - 1,500 feet. In the future, platform capability 1,000 feet by 1979 - 1980. UWC 3,000 feet by 1978 - 1980	Now	Fixed 24 well platform in 600 feet ready for production 4 to 5 years after field discovery and delineation. Pipelines or barges required for production
2. Middle Atlantic	Same as North Atlantic	At present, fixed platforms 800 feet. UWC 1,200 - 1,500 feet. In the future, platform capability 1,000 feet by 1979 - 1980. UWC 3,000 feet by 1979 - 1980	Now	Same as North Atlantic
3. South Atlantic	Same as North Atlantic	Same as Middle Atlantic	Now	Same as North Atlantic
4. East Gulf 5. Central Gulf 6. West Gulf	Same as North Atlantic	At present, fixed platforms 1,000 feet. UWC 1,200 - 1,500 feet. In the future, UWC 3,000 feet by 1978 - 1980	Now	At present, fixed 24 well platform in 400 feet ready for production 3 to 4 years after field discovery and delineation. Fixed 40 well platform in 1,000 feet ready for production 6 to 8 years after field discovery and delineation. In the future, production from UWC in 1,000 - 3,000 feet by mid-1980's. Because of special treating facilities required, sour (H_2S) hydrocarbon production in Area 4 may add 1 to 2 years
7. Southern Cal. Borderland 8. Santa Barbara 9. North & Central Cal 10. Washington - Oregon	Same as North Atlantic	For Areas 7 and 8, same as Gulf of Mexico. For Areas 9 and 10, same as North Atlantic	Now	For Areas 7 and 8, same as Gulf of Mexico. For Areas 9 and 10, same as North Atlantic. Earthquake zones require special surveys and engineering considerations
11. Cook Inlet 12. Southern Aleutian Shelf 13. Gulf of Alaska 14. Bristol Bay S. of 55° Lat	Jack-ups 300 - 350 feet. Drillships and semi-submersibles 1,200 - 1,500 feet	Platforms 600 feet for ice free areas. For seasonal ice areas such as Bristol Bay and Lower Cook Inlet, platforms to 200 feet feasible	Now	At present, fixed 24 well platform for ice-free areas in 600 feet ready for production 4 ½ to 6 years after field discovery and delineation, in 200 feet ready for production 4 to 5 years. Earthquake zones require special surveys and engineering considerations that could cause delays. Satellite UWC could extend depth 100 - 200 feet in most areas. In the future, production in ice-free areas in 1,500 feet feasible 1980 - 1985. Production in seasonal ice areas beyond 200 feet feasible 1980 - 1985
15. Bristol Bay N. of 55° Lat 16. Bering Sea Shelf 17. Beaufort Sea 18. Chukchi Sea	Jack-ups 300 - 350 feet. Drillships and semi-submersibles 1,200 - 1,500 feet during ice free periods. Gravel islands and island-type structures 50 feet. Land fast ice (as in Kotzebue Sound) may be drilled. Conventional offshore rigs not useable in areas of heavy moving ice. Anticipate that current R & D projects such as ice breaking drillships will extend present capabilities	Gravel islands and island type structures 50 feet. Concrete or steel cone structures may be feasible to 200 feet. Drillship capability may permit UWC if latter can be designed for potential bottom ice conditions	Now, selectively, with some modifications to existing equipment for specific areas	At present, production from gravel islands and island type structures 4 to 5 years after field discovery and delineation, provided development drilling from same island as exploration drilling. In the future, development cycle periods for deeper water dependent on current R & D. Additional overland pipelines required for moving petroleum to southern ports, since the pipeline presently under construction will be fully used by projected North Slope production forecasted from current discoveries. Earthquake zones require special surveys and engineering considerations.

* All jack-up rigs derated from indicated maximum water depth capability during severe weather seasons

† "Ready for production" assumes all development wells drilled before initial production, one rig per platform. Development period related to number of wells, drilling depth, drilling conditions. Number of wells not limited to examples given.

2.2 OFFSHORE DEVELOPMENT PROJECTS

Five major projects are classified as entirely or principally offshore in location. These include the surveying, drilling, and transportation of oil and gas from the Outer Continental Shelf to shoreside facilities for storage or processing. All these projects require large "front-end" expenditures and some may be marginal investments. Location and use of these facilities offshore control, to a large extent, the location and type of onshore support facilities.

The offshore development projects presented in this section are:

2.2.1 Geophysical Surveying
2.2.2 Exploratory Drilling
2.2.3 Production Drilling
2.2.4 Pipelines
2.2.5 Offshore Mooring and Tanker Operations

2.2.1 Geophysical Surveying

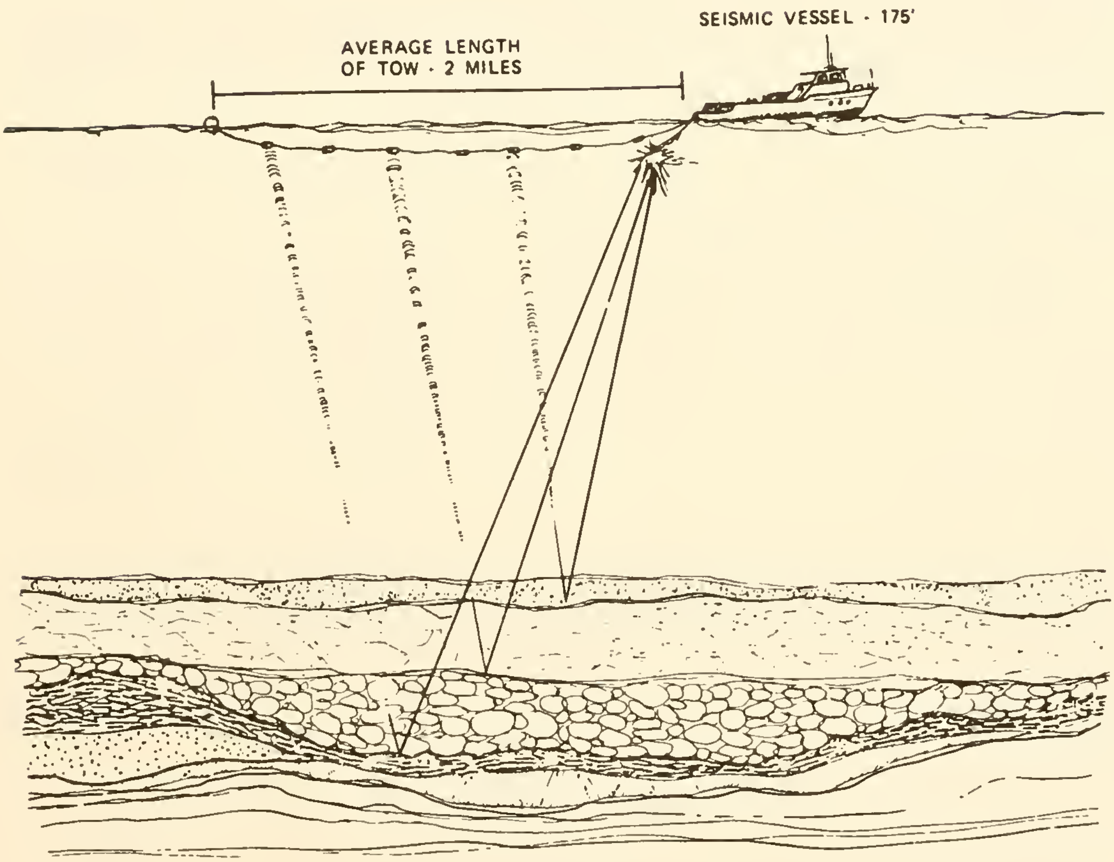
The initial step in searching for potential petroleum deposits is to analyze data about geologic characteristics of an area, derived through a geophysical survey. The prime objective of that analysis is to identify and locate reservoir rocks and structures (traps) in which oil and gas could have accumulated. A knowledge of the subsurface is also helpful in detecting near-surface conditions such as fault zones (prevalent off California and Alaska) which pose possible hazards to exploration and subsequent production operations.

Description

The seismic survey is the principal geophysical technique employed by oil companies or their contractors for identification of potential lease tracts that hold the most promise. Figure 9 schematically illustrates the operation of a marine seismic system. During seismic surveying operations, a ship with a crew of six to ten travels along a predetermined path or grid towing signal-generating and recording equipment. The signal generated by the energy source (usually air or gas guns are used), results in a series of sonic pulses or seismic waves, that travel through the water and are reflected and refracted by the underlying rock formations. The returning sonic waves are detected by hydrophones towed by the vessels and are recorded in digital format on magnetic tape. The data is translated into vertical cross-sections of each traverse. The cross-sections are then interpreted to determine the presence of possible structural and stratigraphic traps. Subsurface structure contour maps are prepared for selected formations which appear promising.

One method for analyzing seismic data covering selected geologic formations that has received wide industry acceptance is the "bright spot" technique. This technique has been credited with the direct determination of oil and gas prior to drilling in young sediments with a relatively simple geologic structure. This method is based upon locating large variations in seismic reflections, the greater the difference in velocity between two formations, the greater the amplitude of the reflected energy. As the velocity in a petroleum-bearing sandstone (reservoir rock) is lower than either a water-bearing or non-porous sandstone, the presence of petroleum-bearing sandstone will cause a two to five fold increase in the amplitude of the reflected energy. By processing the seismic data to highlight the true amplitudes of the reflections, it is possible to directly identify petroleum-bearing formations. The data displays "strong events" or "bright spots" when abnormally broad contrasts in velocity are present. While the technique has been successfully employed in certain areas, it is not applicable in all cases.

Figure 9. Seismic operations (Source: Reference 16).



In addition to the deep penetration seismic survey activity described above, other types of surveys are performed, such as shallow penetration high resolution acoustic (sonar) studies to locate ocean floor geologic hazards such as faults and mudslides. Results of these surveys are used to aid in the selection of specific exploratory drilling and production drilling sites.

Another type of survey involves the use of a magnetic sensor or magnetometer to locate anomalies. The magnetometer is towed behind the survey ship, similar to a seismic survey. The data is interpreted to detect small warps or anomalies in the earth's magnetic field produced by the different types of rocks. These anomalies indicate the structure of subsurface rocks and petroleum-bearing strata.

Survey vessels often use gravity meters to measure slight changes in the force of gravity attributable to different rocks of varying densities over which the vessel passes.

The geophysical survey data collected by one or more techniques described above may be supplemented by geologic studies of rock outcrops on or near the sea bottom. The goals of these studies include age determination, stratigraphic correlation assessment of the lithologic character, and evaluation of mechanical properties (such as load strength and compressibility), necessary for design of platforms and pipelines in specific locations.

A process that may conclude this phase is drilling a Continental Offshore Stratigraphic Test (COST) well. Core samples taken during drilling are used to confirm conclusions about the rock layers and structural composition of the rock. These tests, drilled from a mobile rig, may penetrate up to 16,000 feet. According to USGS regulations, stratigraphic test wells must be drilled off of any presumed geologic structure and no direct testing for oil and gas is permitted. The data obtained from analyzing the test must be released within 60 days after the initial lease sale in the area. Various well logging tests and an evaluation of drill cores and cuttings can be used to analyze the geologic sections that indicate the presence of source and reservoir rocks and other factors which are indicators of possible petroleum accumulations in the adjacent structures.

Two deep stratigraphic tests financed by a consortium of more than 20 companies were completed in the Baltimore Canyon trough in the spring of 1976 and in the Georges Bank area during the summer of 1976.

Site Requirements

With the exception of COST holes, geophysical survey has no significant onshore siting requirements. The survey vessel, requiring a berthing space, is similar in size and needs to a commercial fishing

vessel. A rig to drill COST holes is identical to an exploratory rig, described in Section 2.2.2, and has similar offshore and onshore support requirements.

Construction/Installation

Vessels used in this activity are constructed at established shipyards. (See Section 2.3.2.) No unusual equipment or processes are required. The installation of one COST well has the same characteristics and impacts as an exploratory drill rig discussed in Section 2.2.2 following.

Operation

Survey vessels operate offshore, coming to dock to take on supplies and fuel or to tie up between contracts. There is little that would distinguish their operation from a deep sea commercial fishing vessel. The operations of an exploratory drill rig are described in Section 2.2.2.

Community

Survey vessels have no discernible impacts on coastal communities. Shipboard labor is contracted with the vessel offering no local employment opportunities. Onshore businesses that provide the services needed by this type of vessel, such as marine fuel and food supplies, (See Section 2.3.3) benefit from additional business. Effects of the exploratory drilling rig, including data on employment and induced effects, are minimal.

Effects on Living Systems

Geophysical surveys conducted offshore in deep waters do not affect living resources, if conducted under established regulations. Before modern techniques were perfected, dynamite was frequently used, causing fish kills in small areas. Modern seismic techniques have not caused any documented adverse impacts to living systems. Geophysical surveys do not require any action to eliminate any potential for adverse impacts to living systems. Effects of drill rigs on living systems are described in Section 2.2.2.

Regulatory Factors

Outer Continental Shelf exploration and development activities are generally managed by the United States Geological Survey. The COST

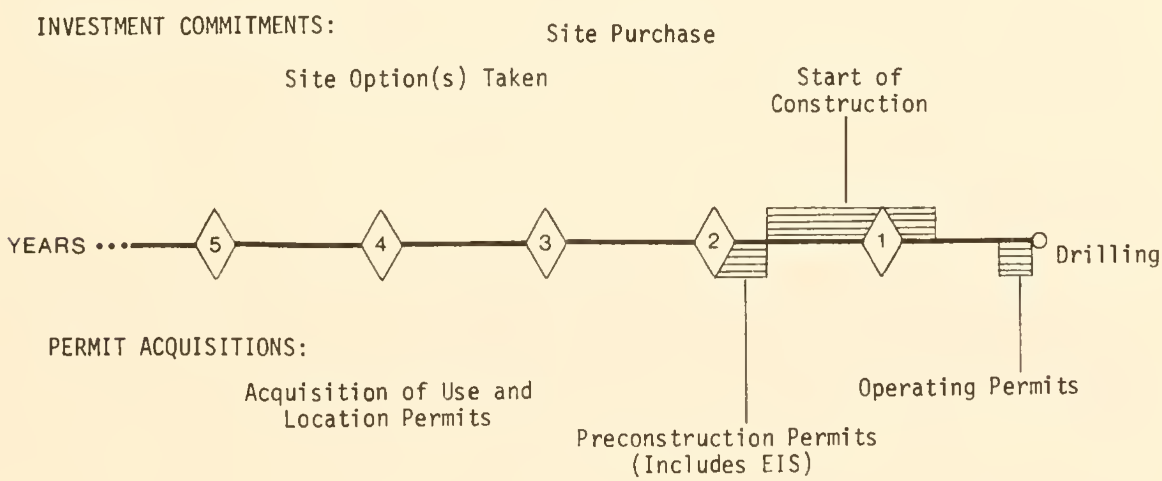
hole and associated exploration activities require specific permits from USGS, the Coast Guard and the Corps of Engineers. In most respects these are the same permits required for exploratory activity after leasing. However, only one COST hole is drilled in a proposed leasing area and precedes the definition of specific lease conditions which also governs post-leasing exploration and development.

2.2.2 Exploratory Drilling

Exploratory drilling is the major activity of the exploration phase of the offshore petroleum development process. This activity follows the geophysical surveying of the offshore field. If the exploration is successful, it is followed by production drilling (Section 2.2.3).

Exploratory drilling occurs after seismic surveying has determined that a commercial potential for oil and/or gas exists in an area and after a Federal lease-sale, in which tracts are awarded to oil and gas companies on the basis of competitive bidding (See Figure 10). The lease award gives the lessee exclusive rights and privileges to drill, extract, and dispose of oil and gas deposits for a period of five years or as long as oil and gas may be economically produced from the tract.

Figure 10. Exploratory drilling - project implementation schedule.



The petroleum company is obligated to proceed with the tract exploration in a diligent manner or run the risk of losing development rights to the tract.

Description

Exploratory drilling determines the location, extent, and quantity of oil or gas. This phase differs from production drilling of wells for the retrieval of commercial quantities of crude oil defined by exploratory drilling. It also differs from Continental Offshore Stratigraphic Tests (COST wells) which are deep drilling exercises seeking geological information on the types of rocks, layers, and formation pressures in an area to be leased.

The equipment used in exploration drilling is called a "rig." The three major types of rigs used in offshore exploration are jack-up rigs, semi-submersible drilling rigs and drill ships. These rigs are described under Construction/Installation in this section.

Oil companies do not own drilling rigs; instead, they contract for both rigs and crews from a drilling company. The equipment and crew drilling a hole belong to the drilling company; the hole belongs to the oil company.

Since the oil companies do not own rigs, they suffer no financial consequences when work is not available. Instead, the oil companies can wait until rig rental rates drop before drawing up contracts. Since rates may be artificially low for some years, exploratory drilling in speculative areas may increase. At present, though, the oil industry has been reducing exploration and concentrating on development.

Site Requirements

Exploration is conducted within tracts leased by oil companies, in areas suggested during geophysical surveying. There are no specific site requirements for rigs as they are mobile. They use service bases which do have site requirements and which are described in Section 2.3.1.

Construction/Installation

Offshore oil exploration today is significantly different in both complexity and cost when compared with operations only 20 years ago. The early offshore wells were drilled in relatively shallow and protected waters. However, as exploration moved further offshore, it was necessary to use larger steel platforms that were permanently affixed to a specific site; this was usually accomplished by driving piles into the shallow

sea floor. The cost of a fixed platform, especially the expense and difficulty of moving it, reached a point where it could only be employed for production purposes and a new type of mobile rig had to be developed for exploration.

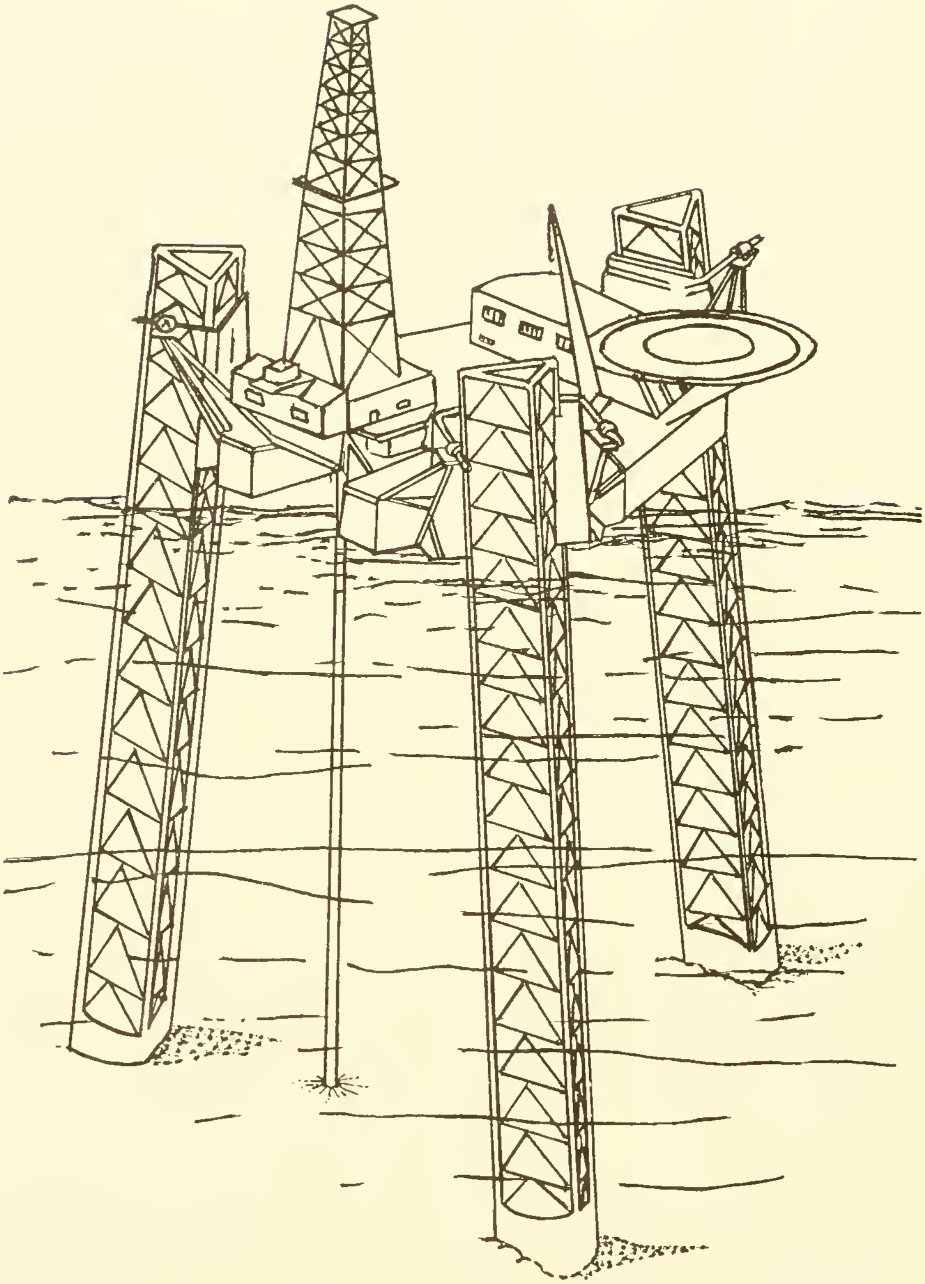
A different type of platform was developed which entailed the mounting of derricks on river barges which could be used in the shallow coastal swamp areas of Louisiana. These platforms called bottom-supported submersible platforms or simply submersibles proved to be adaptable for shallow exploratory offshore drilling. The submersible was generally towed to a well site and then sunk in shallow water. After the drilling was completed, the submersible was pumped out, refloated, and towed to a new location. Although developed more than 20 years ago during the infancy stage of offshore operations, there are still about 20 of these rigs in use today. (However, submersibles are of no value for exploratory drilling in the deeper waters of proposed lease areas.)

Jack-up Rig: A type of bottom-supported rig which has evolved from the submersible is the jack-up rig. By the end of 1976 approximately 180 jack-up rigs were in use worldwide. Figure 11 is a diagrammatic illustration of this type of rig. The jack-up rig is essentially a floating, barge-like hull that supports a platform. Drilling equipment and crew quarters are mounted on the platform. Three legs, each up to 400 feet long, are fitted vertically through slots in the hull. While the jack-up is being towed to a location, the legs are drawn up, but when the rig is in place over the well site, the legs are lowered mechanically or hydraulically until they reach the sea floor. The platform is "jacked-up" until it has been elevated far enough out of the water to be out of reach of most anticipated waves.

The dimensions and designs of jack-up rigs vary according to weather conditions and water depths. Most jack-up rigs operate in water depths less than 300 feet in calm conditions; they are located in shallower water in areas with rough winter conditions. Jack-up rigs are built and serviced at existing ship yards and other coastal steel fabrication facilities. A representative rig currently in use might have a hull that is about 230 feet by 230 feet and about 25 feet deep with crew accommodations for almost 80 crew members and a drilling penetration capability of up to 25,000 feet. A towing draft of 20 to 30 feet is normally required. Jack-up rigs are extremely stable and provide a secure drilling position when used in the appropriate depths.

Semi-submersible Drilling Rig: The most recent development in floating platforms is the semi-submersible; these have been operable for more than 15 years. It floats, rather than rests on the sea bottom, and is designed to minimize heave, pitch, and roll motions. In a semi-submersible, the major buoyant support for the vessel is placed in pontoons and risers which ride on and above the surface when a semi-submersible is moving; when it is in the drilling mode, the pontoons are sunk well below the waterline by adding ballast.

Figure 11. Jack-up drilling rig for offshore exploration. (Source: Reference 17).



Certain limitations are inherent in the design of semi-submersibles. The addition or loss of weight on these vessels must be carefully compensated for by altering ballast. Semi-submersibles are usually towed to a drilling position, while newer semi-submersibles are often selfpropelled. They require large facilities for construction and servicing. As with jack-ups. they have a towing draft of 20 to 30 feet.

A semi-submersible can be anchored like a drilling barge, or it can be dynamically positioned like a drill ship. Figure 12 is a diagrammatic illustration of a semi-submersible. Some of the recently built semi-submersibles are rather large; one vessel, for example, has a square working platform some 200 feet on a side mounted on six hollow steel columns 26 feet in diameter which in turn are mounted on two pontoons, each 355 feet long, 36 feet wide, and 22 feet deep. A restricted area of at least 1/4 mile and as much as 2 miles surrounding a rig may be required as a buffer/safety zone to prevent fishing and other boating accidents with the rig.

Drill Ship: A drill ship is self-propelled. The drilling platform is situated in the deck; various internal compartments provide crew quarters and storage space for equipment and supplies. The drill is worked from a derrick through a hole in the center of the ship.

Modern drill ships such as the one illustrated in Figure 13 provide greater stability than earlier predecessors. For example, the Glomar 40, a 450-foot ship displacing 14,500 tons, is designed for operations in water depths ranging from 100 feet to 3,000 feet; it has the capability of maintaining operations in winds of 60 miles per hour and waves of 50 feet

The modern technological response to the problems of surge and sway came with the development of a sophisticated technique known as "dynamic positioning." This technology involves the use of electronic devices to take constant readings of a platform's precise geographic position with relation to the ocean floor. The processed data is used to automatically activate one or more of the steering propellors or "thrusters" to keep the platform in proper position over the well. Drill ships incorporating these and other technological features offer the advantages of considerable mobility and deep water drilling capability.

It is not possible to predict precisely which type of drilling rig will be used in each OCS area; but the selection will depend upon a tradeoff of factors including water depth, sea state, and the condition of the sea floor. For anticipated United States OCS work the bottom-supported submersible platform and the drilling barge can be eliminated from consideration since the depth of most areas exceeds their capabilities. Moreover, rough seas could easily capsize drilling barges.

Figure 12. Semi-submersible drilling rig for offshore exploration (Source: Reference 18).

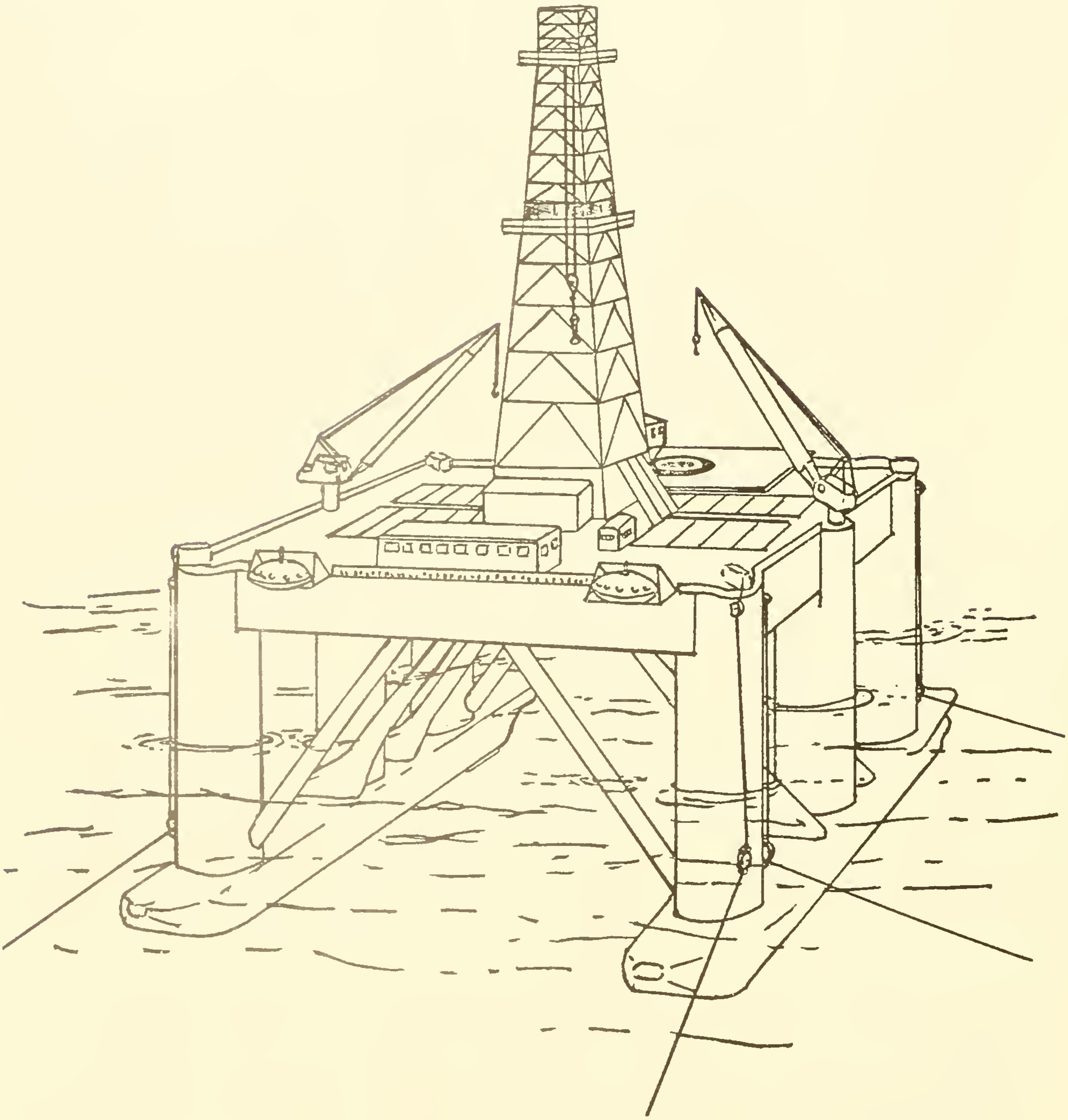
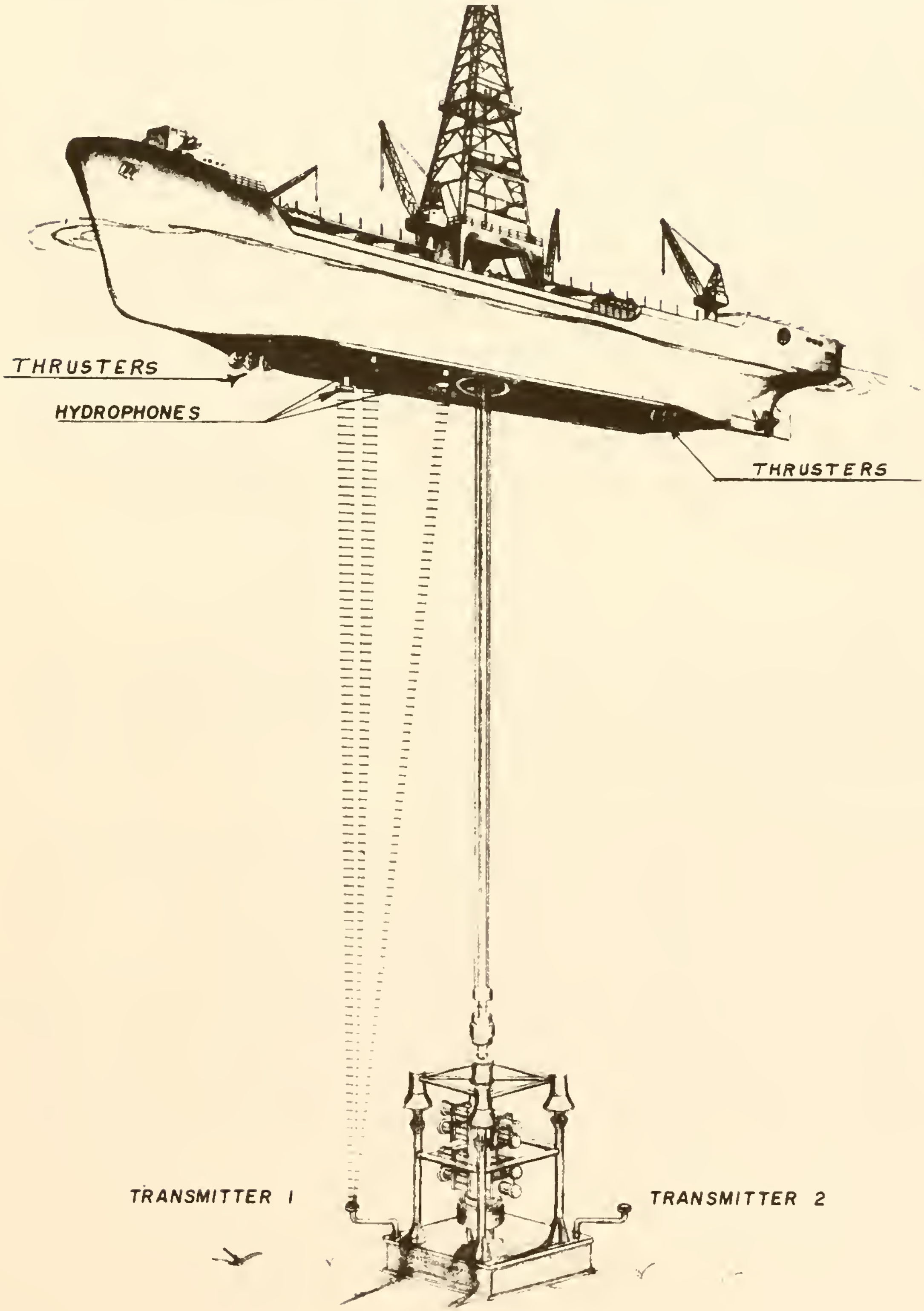


Figure 13. Typical dynamic positioned deep water drill ship (Source: Reference 18).



The jack-up rig is the only bottom-supported platform that may be used in the OCS. Drilling rigs of this type are readily available as they make up some 40 percent of the world's offshore exploratory rig fleet. One of several important factors the operators will consider in their selection of rigs is whether jack-ups are sufficiently mobile for the job. Unlike other platforms, a jack-up rig is secured to the sea floor to enhance its stability and to increase its resistance to wave action. Preparing the jack-up for a move to a new location and then re-securing it to the sea floor can take several weeks, depending on sea and sea-floor conditions.

Cost factors aside,, the choice of rig for a particular OCS site is based on a tradeoff between the demands of mobility and the desired limits of vertical variation between the drilling platform and the wellhead. If only a few wells or very deep wells are to be drilled, mobility might be sacrificed for the greater stability of jack-ups. However, if numerous wells are to be drilled, a floating platform may be more feasible. Table 10 provides a comparative account of the three major types of mobile exploratory drilling rigs--jack-up, drill ship, and semi-submersible--by four major variables in selection (depth, capability and other factors are judgemental and therefore vary from source to source).

Operations

The exploration operations employed offshore, at sometimes great depth, are an extension of the land methods that have developed over the past seventy-five years. The only real difference is the specialized hardware and the associated industries which developed in response to that particular type of drilling.

All exploratory rigs have the necessary equipment on board for drilling, but they must be supplied from service bases on the shore by service boats and helicopters. The boats usually bring drilling muds and drilling pipes on a regular basis if the distance from shore is not excessively great; helicopters may be employed when distance to the rig is a factor and too much time would be consumed in boat transit. Helicopters are also utilized for interim trips, providing a quick, efficient means of contact with the rig. Crewboats or possibly helicopters are employed to change the drilling rig crews; this occurs typically once every seven days or two weeks, but it varies with projects and companies. Food is brought out at these changes, and solid waste is collected from the rigs. Sewage is treated on board the rig or drill ship and discharged into the sea.

Table 10. Advantages and Disadvantages of Major Types of Mobile Exploratory Offshore Drilling Rigs (Source: Reference 19)

RIG TYPE	MOBILITY	STABILITY	COSTS IN MILLIONS OF 1975 DOLLARS[1]	MAXIMUM WATER DEPTH CAPABILITY
JACK-UP	FAIR TO GOOD: BARGE-LIKE HULL DESIGN AND HYDRAULIC MECHANISM PERMITS EFFICIENT RELOCATION PROCEDURE.	EXCELLENT: BOTTOM SUPPORT PROVIDES SECURE DRILLING POSITION IN WATER 300' OR LESS.	HIGH: 27.0 LOW: 4.5 AVERAGE: 16.3	300 ft.
DRILLSHIP	EXCELLENT: CAPABLE OF QUICKLY RELOCATING WITHIN A DRILLING FIELD OR TO ANOTHER REGION.	POOR TO FAIR: EASILY AFFECTED BY HIGH WAVE ACTION AND POOR WEATHER.	HIGH: 48.0 LOW: 20.0 AVERAGE: 23.8	600-1500 ft.
SEMI-SUBMERSIBLE	GOOD TO EXCELLENT: DESIGN CONDITIONS PERMIT HIGHLY EFFICIENT MOVING OPERATION WHETHER SELF-PROPELLED OR UNDER TOW.	GOOD TO EXCELLENT: CAPABLE OF OPERATING IN POOR WEATHER CONDITIONS AND VERY DEEP WATER, STABILITY IS EXCEEDED ONLY BY BOTTOM SUPPORTED STRUCTURE.	HIGH: 50 LOW: 16 AVERAGE: 29.7	600-1000 ft.

[1] OFFSHORE RIG DATA SERVICE, 1975

Community Effects

An exploratory drill rig is supported from temporary service bases which are discussed in Section 2.3.1. The primary onshore effect to the community from exploratory drilling oil is through employment and wages generated.

Employment: Personnel requirements for semi-submersible rigs may include 3 people onshore, 36 men on the platform working in each of 4 crews, 30 contract service personnel working in each of 2 crews, and 10 marine personnel. The total employment, therefore, is 217 of which 102 are on the rig at any one time [20]. Other employment estimates per rig for the Mid Atlantic region fall as low as 113 employees [21]. Variation in employment per rig varies with the type of equipment, rather than the nature and location of the frontier area. For the Mid Atlantic lease sale, 80 employees (37 percent) were estimated to be hired locally. An additional 87 individuals were estimated to maintain temporary local residences while the drill ships worked on site. The remaining 50 individuals would commute home during the seven days they were off duty [20].

Total earnings for the 167 employees operating a semi-submersible drilling rig, who reside in the local area, both temporary and permanent, is estimated as $3,300,000, while those who left the area (50 employees) earn approximately $1,000,000.

Induced Effects: The money going out for wages will have a multiplier effect when it enters the local economy to purchase goods and services. An average exploratory well takes approximately 3 months to drill to a depth of 14,000 feet, but variables such as weather conditions and sediment characteristics influence the length of time. Therefore, the total effect on the local area depends on how many wells are drilled both at one time and in total. In a promising field several rigs might operate at the same time. If a single coastal port is much closer to the offshore field, then supporting activities will concentrate at one location, but if several ports offer similar advantages, then the total effect may be dispersed over a wider area.

The effect on a local community may be less than it might initially appear. Many temporary residents will send portions of their earnings home. In addition, during the seven-day off period, they may leave the local area for extended time periods. From the perspective of the local community, these individuals require virtually no services. Therefore, any local expenditures are positive as they are offset by negligible public costs. In addition some local employment opportunities are provided.

Effects on Living Resources

Exploratory drilling is characterized by major potential fish and wildlife impacts from: (1) removal of ocean bottom habitat; (2) drill cuttings and other discharges from the rig; (3) blowouts; and (4) servicing requirements. Sponsor actions will be required during location and operation phases to reduce drilling hazards.

Location: In spite of the relatively short duration that a rig will be on location, the sponsor must make provision for: (1) ecological potential of site; (2) disruption of bottom habitat particularly live bottoms (coral reefs, etc.); and (3) interference with fish and wildlife resources either indigenous to or migrating through the area. Drill cuttings disposal can lead to such adverse ecologic effects as (1) turbidity; (2) eutrophication; (3) toxification.

Operation: The sponsor's major environmental problem in operation will be meeting pollutant discharge standards on waste disposal; e.g., drill cuttings, drilling muds, and brines. Solid wastes are returned for on-shore disposal.

Regulatory Factors

Exploratory drilling takes place in an area of exclusive Federal jurisdiction on the Outer Continental Shelf. The OCS Lands Act assigns management responsibility to the Department of the Interior. The United States Geological Survey manages exploratory drilling activities. Both the Corps of Engineers and the Coast Guard must also issue permits before exploratory drilling may proceed. The states have no formal role in this process unless they have an approved Coastal Zone Management Plan. (Coastal Zone Management Act of 1972, as amended 1976, Section 307 (c) (3) (B).)

Federal Role: After a lease sale on the Outer Continental Shelf, the USGS may issue permits under Section 11 of the OCS Lands Act for geophysical and geological exploration activities. The permit is issued by the Area Oil and Gas Supervisor, USGS, under regulations found in Volume 30 of the Code of Federal Regulations, Section 251.

The lessee must submit a plan with the Area Oil and Gas Supervisor of the USGS which becomes the basis for specific permits. This plan must include: (1) a description of drilling vessels, platforms, or other structures showing the location, the design, and the major features thereof, including features pertaining to pollution prevention and control; (2) the general location of each well, including surface and projected bottom hole location for directionally drilled wells; (3) structural interpretations based on available geological and geophysical data; and (4) such other pertinent data as the supervisor may prescribe.

In reviewing these plans, USGS has relied on the environmental impact evaluation prepared by BLM and FWS prior to leasing. Normally many of the suggested conditions or hazards are already accounted for in lease stipulations developed by BLM, FWS and USGS, under Secretarial Order 2974. To supplement these conditions, the Area Oil and Gas Supervisor may issue operating orders that govern exploration, drilling, and production in leased areas.

The Fish and Wildlife Service contributes to the conditions which may be attached to the exploratory drilling permit, BLM and FWS may collaborate in designing biological surveys (in satisfaction of a lease sale stipulation) to ascertain what effects the drilling would have on "significant biological resources." Environmental assessment is incorporated in the lease tract evaluation program managed by the Bureau of Land Management.

The Fish and Wildlife Service is also asked to comment on Corps of Engineers and Coast Guard permits required for temporary and permanent OCS structures. However ,the Corps has interpreted its statutory authority to apply only to navigational and security aspects, thus excluding direct environmental consequences from Outer Continental Shelf permit review; the Service is left with few opportunities to comment.

State Role: The 1976 Amendments to the Coastal Zone Management Act added a provision that may bring states into this process insofar as exploration brings associated coastal zone impacts. Section 307 (c) (3) (B) requires that any "plan for the exploration or development of... any area which has been leased under the Outer Continental Shelf Lands Act...shall attach to such plan a certification that each activity which is described in detail in such plan complies with such State's approved management program...."

Development Strategy

Data obtained from exploratory drilling is proprietary information, owned by individual oil and/or gas companies. As such, this data is not released to the general public, except upon the request of the company. A copy of the findings, however, is given to USGS in compliance with Federal regulations, but still remains proprietary.

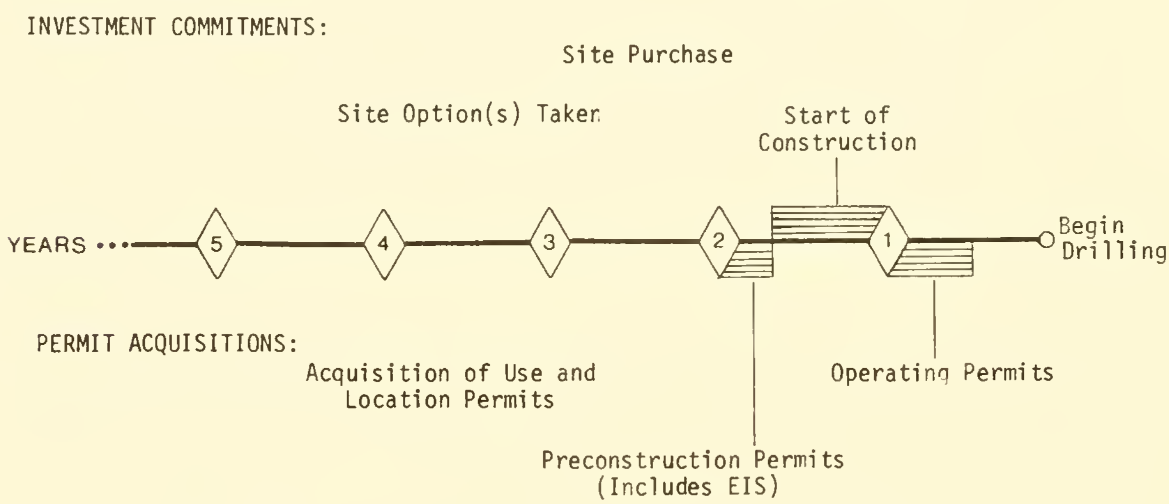
In cases where a COST hole has been drilled in a frontier area by a consortium of companies, information can be released to the public either (1) after five years from the drilling date, or (2) within 60 days after a lease-sale is held within a 50 mile radius of the drilling site. Within these specified time periods oil and gas, companies have exclusive rights to the information obtained during exploratory drilling, without obligation to make the data public. USGS can purchase the information from the companies.

Each group of companies must obtain, analyze, and make judgmental decisions on its own data with the hope that their assessments and predictions on the location of oil and gas reserves are more accurate than their competitors. The results and findings from exploratory drilling will lead to field size determination and possibly production drilling.

2.2.3 Production Drilling

Production platforms are located on offshore leased tracts to extract petroleum resources and to house the crew, materials, and equipment for offshore operations. Platforms are designed and constructed to meet the specific requirements and conditions of the installation site (see Figure 14). Concern about spill potential from operations on production platforms is quite high in onshore areas. This concern, and its effect on industry's strategies, will be emphasized in this section. Production platforms are constructed in platform fabrication yards, which are covered in Section 2.3.4.

Figure 14. Production drilling - project implementation schedule.



Description

Production platforms may be fixed-pile platforms or gravity platforms. Gravity platforms may be constructed with cement or steel as the major component. All platforms consist of two parts: the deck and the jacket. The jacket, which serves as a base supporting the deck section, is the large skeletal framework often visualized when offshore oilfield development is discussed.

The fixed-pile platform, commonly used in the United States, is a steel framework. A fixed-pile platform is shown in Figure 15. Gravity platforms, using concrete in the North Sea and steel off West Africa, are rather recent innovations. The comparative advantages and liabilities for selecting a gravity or a fixed-pile platform are discussed later. At the present time industry anticipates all platforms used in United States OCS frontier development will be the fixed-pile platform type.

The deck assembly includes modular units that may be interchanged for each of the three operations conducted on a production platform: production drilling, routine maintenance, and workover. Production wells are drilled with a derrick. Figure 16 illustrates a production platform drilling several wells. Pipe, drilling muds, and other necessary equipment are periodically shipped to the platform and stored on board. After wells are drilled, the drilling equipment is removed, so that only crew quarters, monitoring, and safety equipment remain. As many as sixty wells may be drilled directionally from a single platform.

Site Requirements

A production platform is situated within a leased tract, a square usually encompassing approximately 9 square miles. A platform may generally be situated at any location in the tract. This location is restricted when the adjacent tract is owned by another company. Companies that will be in different tracts but will share a common reservoir (oil bearing geological structure) will try to establish a joint venture. The U.S. Geological Survey also desires and may require joint ventures ("unitization") to achieve the Maximum Effecient Rate (MER) of the reservoir. Several factors influence selection of a specific site including subsea surface characteristics, reservoir characteristics, ownership of adjacent tracts, and lease stipulations controlling activities within.

The greatest single factor in selecting a location for a platform is a subsurface geology. Bottom conditions, including surface sediments and relief, limit feasible locations. Steep slopes and soft sediments are undesirable bottom conditions. If oil is found under these surface conditions, directional drilling, which has a horizontal range of approximately one mile, is one method for overcoming the problem.

Figure 15. Example of a fixed-pile (production drilling) platform (Source: Reference 22).

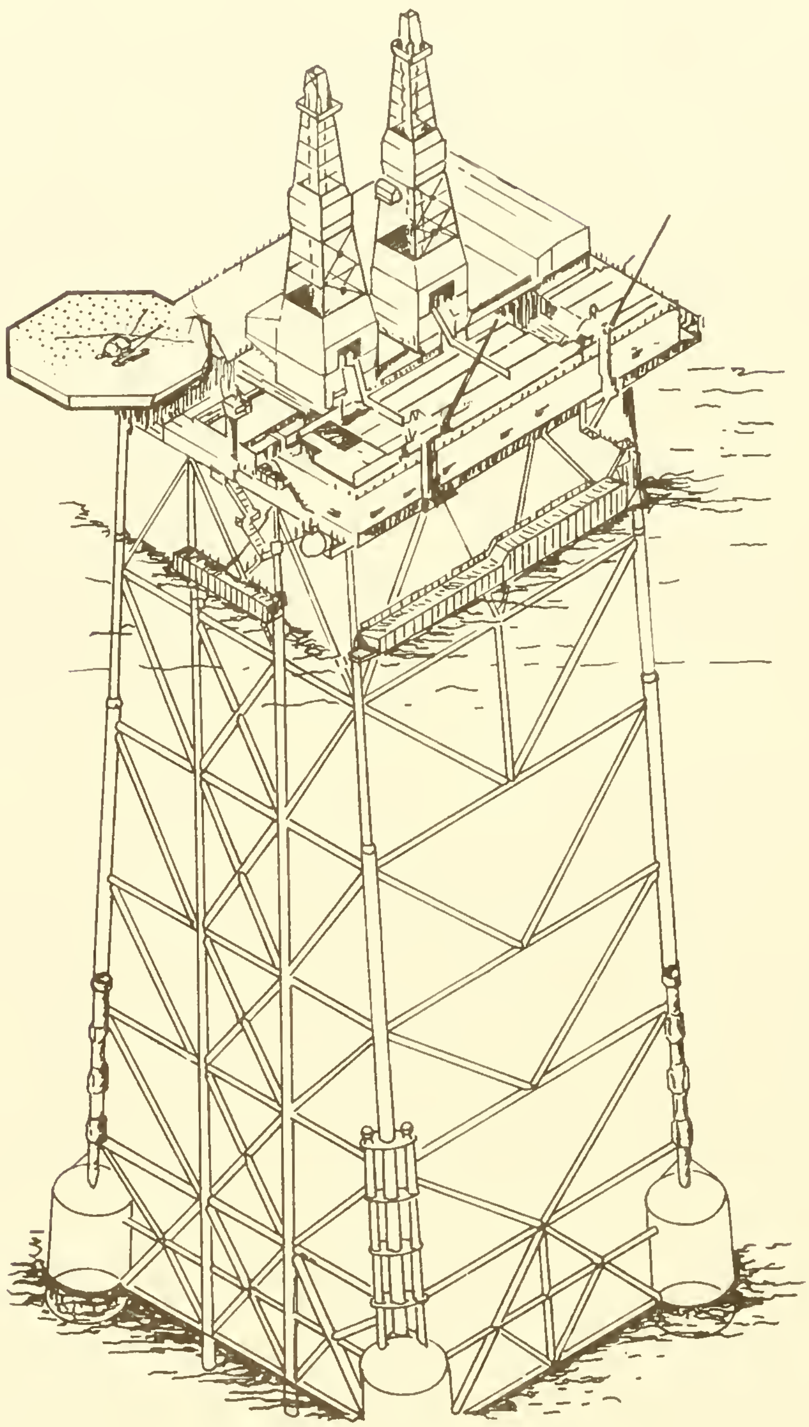
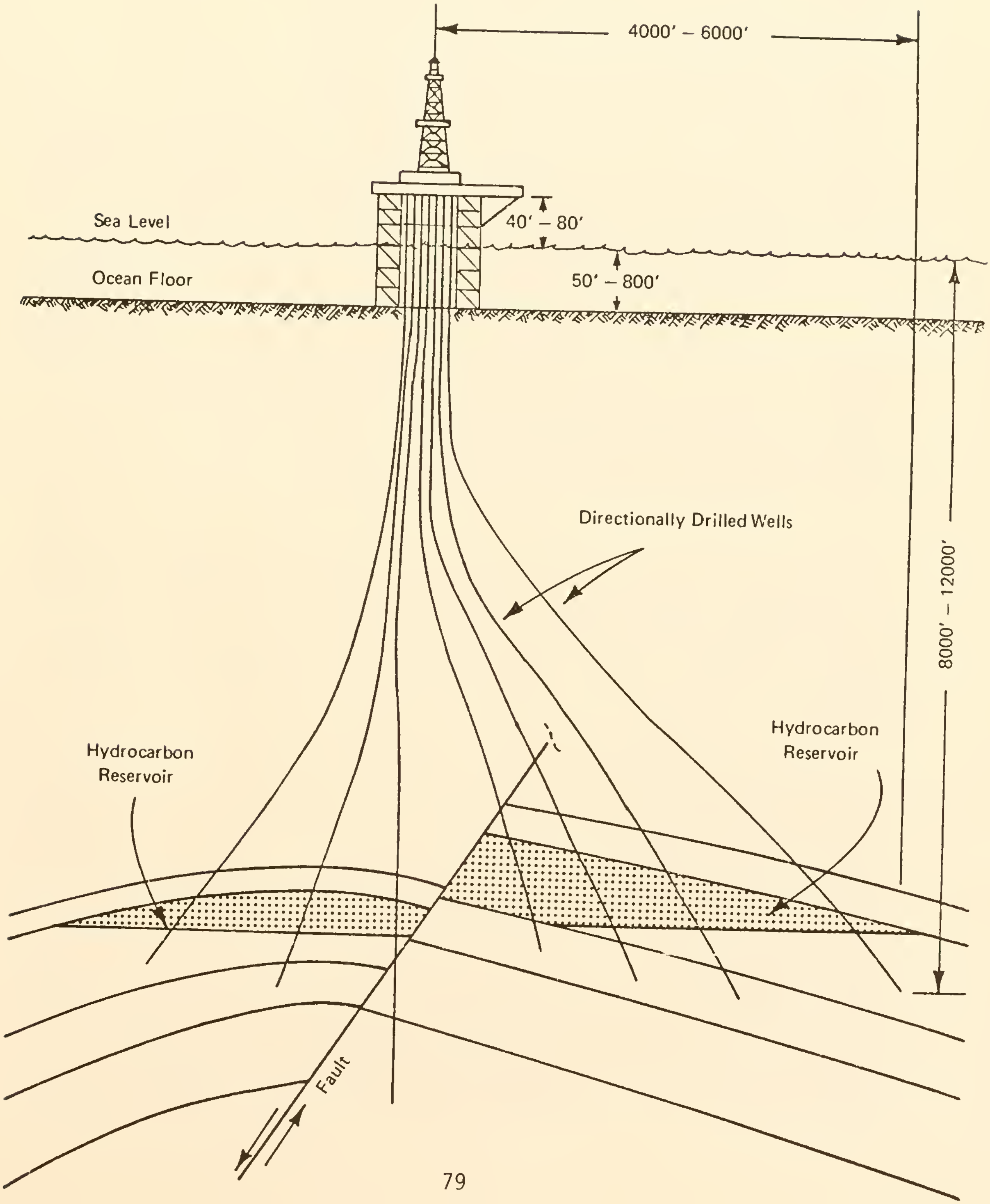


Figure 16. Typical directionally drilled wells (Source: Reference 23).



If the subsurface is hard and compact, as in the North Sea, a gravity platform can be used. However, known geologic characteristics of United States frontier areas indicate that soft sediments predominate. Therefore, fixed-pile platforms will likely be used in all frontier areas.

Construction/Installation (Drilling)

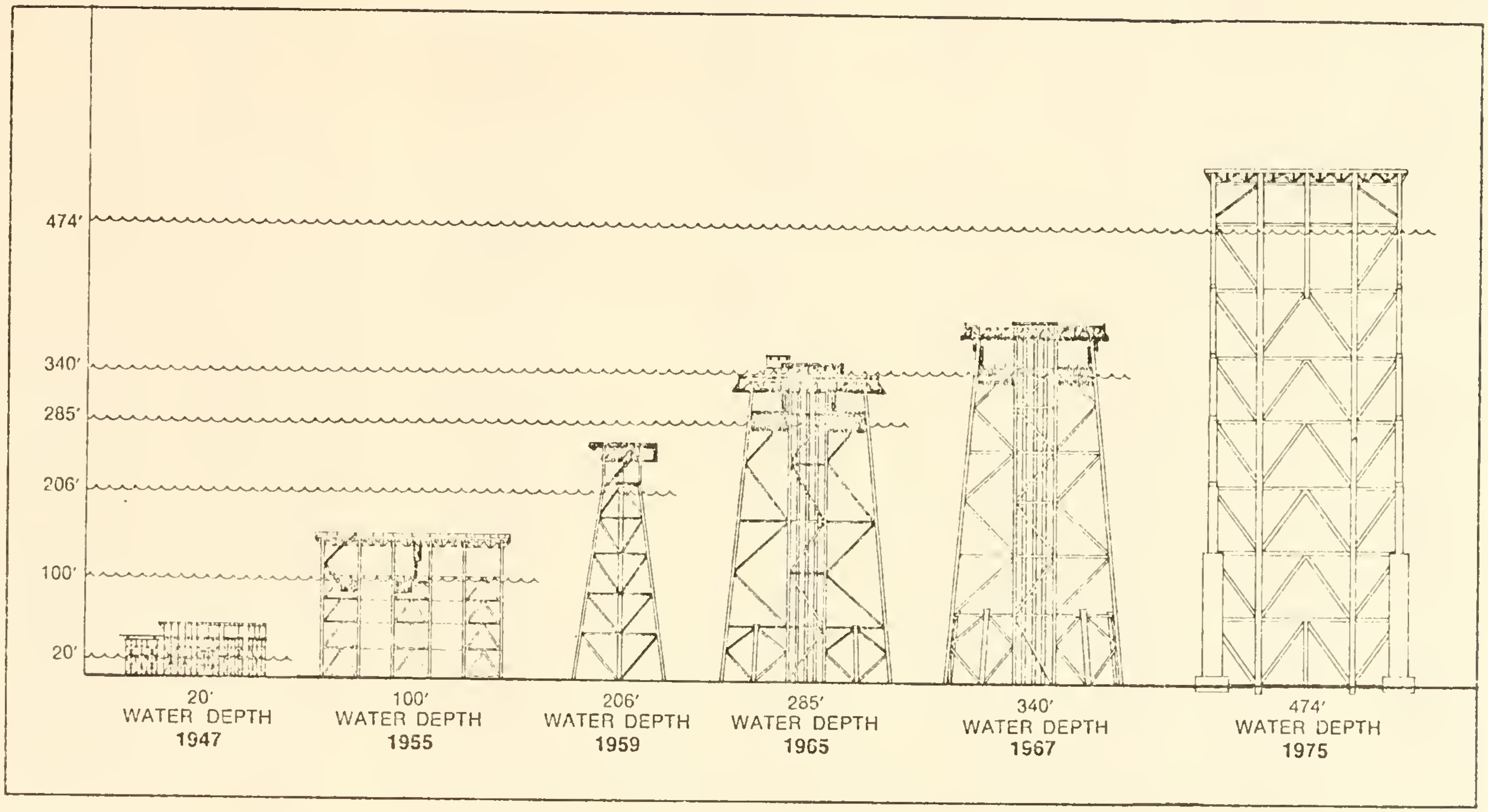
Determining the number of platforms that will be required, their location, and the number of wells per platform is based on a careful analysis of the data obtained during exploratory and appraisal drilling. This analysis involves such factors as the number and thickness of productive horizons, geographic extent, water depth, formation depths, well pressures, etc. Marketing factors will also have a bearing in setting production rates, transport modes, and time frame for recovery.

Production platforms are not standardized. They are custom designed and engineered for a specific location. While many components, such as motors, derricks, cranes, and housing modules are standard items, the structure on which they are housed may have to stand in water depths ranging from 50 to 1,000 feet (Figure 17). Platform engineering must take into account depth, sea floor soil conditions, wave action (including consideration of the 50 to 100 year wave), winds, sea floor stability, and the weight of the structure.

In the Gulf of Mexico, the trend is to construct a master platform, from which wells are drilled, and several satellite platforms on which crew quarters, separators, or compressors, etc. are mounted. Each of the satellites is connected to the main platform by a foot bridge. In the North Sea where weather conditions are more severe and the water depths are greater, thus increasing the cost of platforms, the trend is to locate the wells and all direct support facilities on a single structure.

Production drilling differs somewhat from exploratory drilling. Exploratory rigs are readily moved from one location to another, but a production platform is fixed in place for the life of the field. Modern platforms are designed for drilling multiple wells. The largest platforms have slots to accommodate as many as sixty wells. Exploratory wells are usually drilled vertically; production wells may be drilled either vertically or directionally. Directional or slant drilling requires the deployment of special production rigs (that are mounted on the platform) which can rotate the drill strings through the drive pipe or conductor pipe that may be set at angles up to 30° in the sea floor. (See Figure 16) The bottom of a slant well may be more than a mile measured in the horizontal direction, from the platform on which it was drilled. Production rigs are usually designed with the derrick mounted on rails so that after each well is completed, the derrick can be readily moved over a new hole. The pace of drilling is slower for production than

Figure 17. Continual technological improvements over the years have permitted the oil industry to extend drilling operations to deeper and deeper waters. (Source: Reference 24).



exploration, due to the need for perforating wells at the proper depth for efficient pumping rates and the need to directionally drill some of the wells to ensure as much coverage of the field as possible.

The series of actions that are required to connect a well with the valves and pipelines for transporting oil and gas to shore is termed well "completion." As each well is drilled, it is lined with concrete and then capped with a seal until the pipelines or other shipment methods are in place and storage tanks are ready to receive the output.

After the pipes, tanks, and processing facilities are installed, sea water is pumped down the production casing of a well to flush out any drilling mud which may have been left. A perforation gun is then lowered into the casing. When it reaches a point opposite a stratum of oil or gas-bearing rock, the gun fires explosive charges through the casing and cement to establish a path for the oil or gas to flow from the formation into the well bore. Another string of pipe termed production tubing is put down the casing and serves as a conduit by which the oil or gas come to the surface. Biocides are injected into the formation to keep bacteria from clogging the flow.

The final operation of completing a well involves the installation of a series of wellhead valves termed a "Christmas tree" that are bolted to the top of the production tubing. Christmas trees may be at ocean floor or on platforms. The two purposes of the Christmas tree are to control the rate oil and gas flows into the tubing and to direct the oil and gas to the various items of platform-mounted processing facilities.

Operations

After the wells are completed, the drilling equipment and most of the crew quarters are removed from the platform. All that remains visible on a production platform is a maze of pipes, valves, coils, tanks, compressors, and other pieces of equipment which serve the following functions:

1. to separate oil and gas from water which has been trapped along with the hydrocarbons in the reservoir rock;

2. in some cases, to separate the associated natural gas from oil for separate flow into a pipeline storage tank, or ship;

3. in other cases, natural gas is pumped back into a reservoir through a separate injection well to help maintain reservoir pressure and thereby maintain production.

All processes and operations are continuously monitored by the platform crew. Their sole functions are maintenance and emergency control. Valves to regulate the flow of hydrocarbons can also be controlled by radio from shore or a nearby platform.

A well may yield combinations of oil, gas, water, sand, and other materials from the productive horizon. The purpose of the automated treatment equipment on the platform is to separate these materials for shipment ashore, reinjection back into the reservoir, or disposal. At high formation pressures, most natural gas associated with oil is in the liquid form. A separate pipeline is justified only if there is a significant recoverable quantity. In that case, the oil and associated gas will be separated. The gas may be processed on the platform to further remove water and other undesirable components such as hydrogen sulfide. However, if the quantity of gas produced is so small as not to warrant the construction of a separate pipeline, then a single pipeline would be used to transport both the oil and gas to shore. If the quantity of gas is limited, in many cases the gas will be reinjected back into the wells to maintain reservoir pressure to force oil to the surface; it may also be used as a platform fuel.

Workover is a periodic operation to improve well production by modifying downhole conditions (caused by sanding of wells and decline in pressure). This operation, requiring crews and equipment including a derrick, is usually conducted approximately ten years after initial start-up (or when a well has production problems) and includes operational and procedures similar to initial well-drilling.

A workover involves the removal of sand, water, and any other substances which may accumulate in a well during production. During workover operations the casing may be perforated at different depths to bring in a new producing zone. In addition, safety equipment together with any artificial pumping apparatus is removed for inspection and overhaul before being reinstalled. Generally, during workover operations, the wells immediately adjacent to the well being worked on will also be shut down for safety.

Community Effects

The major effects of platform installation and operation are: (1) increased local employment relating to onshore facilities; (2) increased waterfront industry and general commerce.

Employment: A platform operation has two major phases with different employment characteristics. Highest employment occurs from the time a platform is first placed offshore until the last well is completed. After completion, the operation of wells under the platform is monitored by a much smaller work force. Estimates of platform employment during production drilling vary from 65 to 217 workers. After the wells are drilled employment drops to an average of 16 employees [25].

Induced Effects: Induced effects during the initial stage of drilling production wells are similar to effects related to exploratory drilling. Employment figures, percentage of crews from the local labor pool, and onshore living patterns are all similar. Onshore support for a platform may be more extensive during this phase, as supply needs are greater and somewhat more diverse.

During the second phase, which begins after the well is completed, employment both offshore and onshore declines rapidly. However, this lower level of employment lasts approximately 20 years, and almost all employees reside in the adjacent onshore area. Very few employees will be new residents. This phase may be punctuated by workover, when employment rises to levels of the first phase for a period of several months. As they were during the initial stage, these employees are primarily temporary residents who will leave the area upon completing the workover; they have very little effect on the community.

Effects on Living Resources

Production drilling has effects of particular concern to fish and wildlife from: (1) removal of ocean bottom habitat; (2) drill cuttings and other discharges from the production platform; (3) oil spills; and (4) increased activity from boats, pumps and other equipment.

Location: Production drilling is basically similar to exploratory drilling except it may continue for a much longer period of time and more drilling occurs from a single site, therefore concentrating drill cuttings and mud. When drill cuttings are disposed overboard, the ocean bottom topography is altered; organisms can become smothered from the silts and sediments. Drill cuttings disposal can lead to increased turbidity, eutrophication, and toxification of local waters. Although new technology has greatly reduced the chance of blowouts, oil spills are still a distinct possibility from production drilling. Spill potentials are reduced because much is known about various field pressures from the exploratory wells previously drilled. Additionally there is a chance of a spill from the transfer of oil between the production platform and tankers or barges prior to pipeline construction. Increased activity from boats operating between the shore and the platform, plus noise from compressors, pumps, and other machinery may cause fish and wildlife to avoid an area which under normal conditions they would have occupied for reproduction, feeding, etc.

Design: The sponsor will have to incorporate design features into a production platform which will exhibit the best in pollution control technology, not only for the present to meet EPA's OCS platform discharge criteria but also in terms of future developments. Appropriate designs would allow easy insertion of pieces of machinery in anticipation of future pollution control regulation.

Construction: The placement of production platforms, especially the gravity type, will have to be done in ways that least disturb the aquatic and benthic habitats. Where gravity platforms are used, bottom habitat will be permanently removed, especially where a platform is used that has a large "mat" or base as its foundation. In addition, the immediate surrounding area will be affected by the construction operations performed on the site. The sponsor will have to take appropriate construction steps, as defined in advance tests, to ensure that neighboring areas will not be affected by excessive turbidity, release of toxic materials, physical disruption, etc.

Operation: The sponsor's major environmental problem in operation will be in meeting pollutant discharge standards on waste disposal. This includes not only petroleum discharges but also brines and sulfurous mixtures which may be extracted from the well. These substances are usually treated on the drilling rig, but it will be necessary to ensure that equipment is always in efficient and proper operating order. EPA may require the barging and disposal of drill cuttings to other ocean disposal sites. Where drilling muds and cuttings contain more than 50 ppm hydrocarbons, they must be treated.

The sponsor will have to exercise diligent care and provide adequate responses when it is determined that platform operations may be interfering with fish and wildlife resources. Production drilling will have to be planned to avoid disturbances to fish and wildlife activities, such as reproduction, rearing of young, and migration. For example, where a species traditionally congregates in a relatively small area for breeding purposes, it may be necessary to institute alternative production drilling schedules. This will allow the species to perform its normal biological functions without outside interference. Such a scheme may incorporate drilling at locations other than those of important species' activities, which will be particularly important in the case of endangered species.

Regulatory Factors

Production drilling on the Outer Continental Shelf occurs in a geographical area under exclusive Federal jurisdiction. Except for recent amendments to the Coastal Zone Management Act, which have yet to take effect, (see Section 2.2.2), states have no formal role in the management process for production drilling. The United States Geological Survey in the Department of the Interior has primary Federal management responsibility. USGS works through a regional agent called the Area Oil and Gas Supervisor who has final authority over day-to-day management decisions.

Federal Role: The leasing process, managed by BLM under the OCS Land Act, results in lease stipulations based on comments by BLM, EPA,

FWS, OSHA and other Federal agencies. By virtue of Secretarial Order 2974, FWS may comment on, prior to USGS approval, rights of easements to construct and maintain platforms, pipelines, etc.; design and plans of same; on exploratory drilling; and on development plans. However their primary concern is in disposal of drill cuttings and effluent discharges which may affect natural resources in the area. These conditions are then incorporated in the management standards enforced by USGS in the post-leasing phases. USGS has the specific responsibility to inspect, monitor, and document the day-to-day activities and operations under OCS leases by on-site inspections. USGS'checklists cover the full spectrum of operational issues except platform-to-shore oil pipelines which are regulated by other federal agencies, principally BLM and platform-to-shore gas pipelines which are regulated by FPC.

Section 1333(f) of the OCS Lands Act extends the authority of the Secretary of the Army (Corps of Engineers) to prevent obstruction to navigation in the navigable waters of the United States, to artificial islands and fixed structures on the Outer Continental Shelf. Pursuant to this authority, the Corps of Engineers must approve a permit application for any production platform. Section 10 of the Rivers and Harbors Act of 1899 authorizes issuance of these permits. Permit review does not include assessment of environmental effects, and is restricted to issues related to navigability. Federal agencies such as FWS and USGS review these applications prior to drilling and installation of production platforms and related equipment.

The Coast Guard has the responsibility for the enforcement of all applicable Federal laws on and under the high seas and navigable waters of the U.S. It administers the laws and regulations to promote safety of life and property, as well as to establish and to maintain aids to navigation for the promotion of the safety on the high seas and waters subject to U.S. jurisdiction.

The siting and operation of a production platform may be subject to additional Federal regulation, particularly related to water quality and discharges of oil and hazardous substances.

State Role: The 1976 Amendments to the Coastal Zone Management Act added a provision that may bring states into this process insofar as exploration brings associated coastal zone impacts. Section 307 (c) (3) (B) requires that any "plan for the exploration or development of... any area which has been leased under the Outer Continental Shelf Lands Act...shall attach to such plan a certification that each activity which is described in detail in such plan complies with such State's approved management program...."

Development Strategy

The sponsor's strategies of production drilling include minimizing construction and installation time and costs, engineering an optimal design, and siting the platform in the best known location on the company's lease holdings.

Platform construction costs are usually minimized by having it constructed at the yard nearest to the field. Yards attempt to locate to maximize attraction of business, as for example, the proposed yard in Astoria, Oregon, which will sell platforms in both Alaska and California. Fabrication of platforms is discussed in Section 2.3.4.

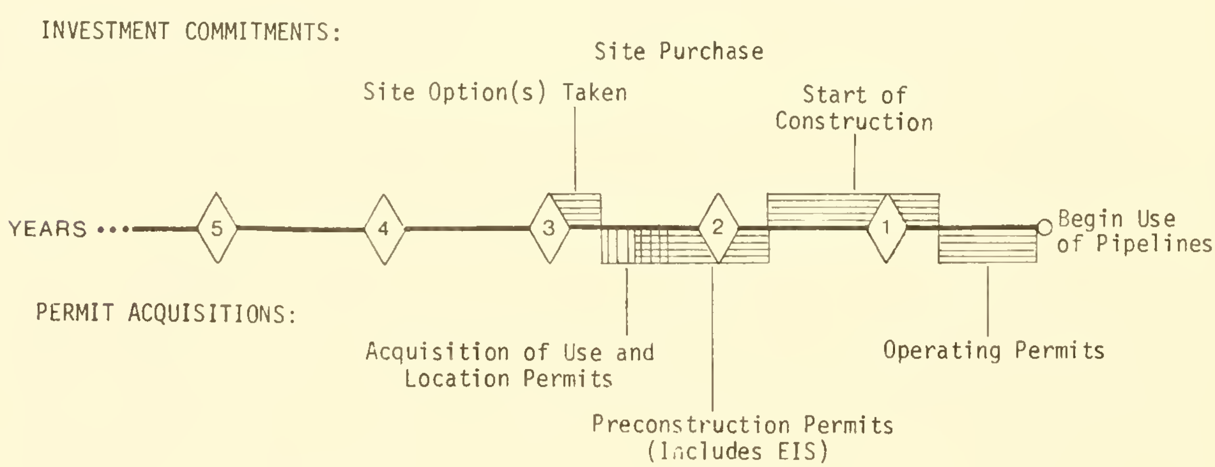
Engineering an optimal design has great flexibility. The platform is designed for a specific site. The design includes locating the deck above the 100 year wave height, determining the technological features of the structure, ascertaining the number of wells to be drilled from the platform, etc. As the petroleum industry moves into deeper waters the costs associated with each platform rise dramatically. In these deeper areas, it becomes increasingly critical for the petroleum company to use fewer platforms to accomplish the same drilling and production tasks. This strategy is implemented through directional drilling and attaching as large a number of wells to a single platform as is possible.

Platform siting was discussed earlier in this section. Locating the best site on a tract involves tradeoffs between the reservoir location and surface conditions on the ocean floor.

2.2.4 Pipelines

Offshore oil and gas are brought ashore by pipelines. They are usually put in by a pipeline-laying company under contract to an oil company. Offshore operators use highly conservative design, emplacement, and operating methodologies for offshore pipelines, apparently because of the costs of underwater installation and the necessary environmental constraints. Performance clearly shows that pipelines are safer and more dependable than tankers and barges [26]. Also, pipelines allow for continuous transportation of petroleum products; they are less dependent on weather conditions which cause other modes of transportation to shut down; production and transportation shutdowns are costly to the oil companies and may result in interruptions of supply to onshore users. It seems likely that pipelines will be used to transport oil from most new U.S. offshore fields if permits for pipeline corridors and landfalls can be readily obtained.

Figure 18. Pipelines - project implementation schedule.



Planning and feasibility studies for the transportation of offshore oil and gas to refinery and consumption centers onshore is initiated simultaneously with the discovery and delineation of a new field. Once the type, extent, and character of the reserves, and the characteristics of the reservoir (porosity, permeability, water or gas pressure) are determined, from exploration drilling, production engineers can determine the amounts of oil and/or gas that will ultimately be produced, production rates over the life of the field, and the approximate location of production platforms. With information on the production rates of platforms and their approximate locations, planning for an oil and/or gas transportation system can commence (See Figure 18).

Although much of this discussion focuses on offshore operations, most of the environmental impact will be incurred nearshore and onshore. The major impacts from pipeline construction occur in the nearshore area. The impacts from the crew, materials, construction equipment, and supply boats occur onshore.

Description

The pipeline is constructed of steel pipe sections, usually about 40 feet long, joined together by advanced welding techniques. Each of the "joints" or pipe sections is coated with a corrosion-inhibiting mastic compound and with a concrete covering which protects the pipe from damage that might occur during handling and laying operations; it also provides weight and stability insuring that the pipe will sink. Both the anti-corrosive coating and the concrete coating are applied at an onshore pipe-coating yard before the pipe is transported to the "lay barge" by supply boats (see Section 2.3.5).

System: The pipeline system consists of: (1) the source of oil or gas; (2) a pressure source located on the production platform or in the formation; (3) intermediate pressure sources along the line (if necessary); (4) a landfall site; and (5) a delivery point. The crude oil or gas may come from a single production platform or from a number of platforms connected by smaller pipelines. In some cases, formation pressures are sufficient to drive gas onshore; in others, compressors are required. Pumping equipment is always required for oil pipelines. Whether intermediate pressure sources are needed is determined by the length of the pipeline, the diameter of the line, the quality and type of fluid being transported, the differential elevations encountered over the route, and the formation pressure.

Gas is piped to a gas processing facility, the shore destination, on line between the landfall site and the market transmission line. Oil is piped to one of two shore destinations, a nearby refinery or a marine terminal, for transshipment to a refinery.

Site Requirements

The most important factor of the pipeline project is the selection of the pipeline corridor. The major object is to minimize the total capital and operating cost of getting the oil or gas from offshore to the desired location onshore. Minimizing the transport cost of oil usually, but not always, requires minimizing the length of the offshore pipeline, because marine pipeline construction is considerably more expensive than most onshore construction (pipelines through wetlands may be as expensive as offshore).

Particular physical and environmental offshore obstacles to be avoided include: deep trenches parallel to or crossing the shoreline, heavy surf zones, soft bottom sediments, sediments subject to liquefaction, extremely hard and rough bottoms, strong bottom currents, sand waves, areas of seismic activity, live reefs, and heavy fishing areas. This may cause a pipeline corridor to deviate from the shortest straight line to the shore.

The Corridor: The preliminary technical assessment of potential pipeline corridors by industry is begun after the size of the prospective pipeline is determined. A number of corridors are selected which originate in the offshore field and terminate at various shore locations which are either feasible locations for transshipment terminals or places where the pipeline can join an onshore pipeline. Each corridor is assessed by developing a preliminary profile from hydrographic charts and estimating the soil conditions and currents along the route.

From this preliminary study, the corridors being considered are narrowed to several options to be considered in detail. Field reconnaissance investigations examine the feasibility of each of the corridors. Sidescan sonar is used to determine the presence of obstacles, debris, and live bottoms. Hydrographic studies determine water depths and bottom topography. Seismic surveys determine the near surface geology and identify potential difficulties along each of the corridors. From these reconnaissance surveys, a construction corridor is chosen by the pipeline company.

The information developed during a reconnaissance survey, even though allowing the final selection of a corridor, is insufficient either to precisely position the pipeline during construction or to develop engineering design and construction criteria. To provide this information, a much more thorough survey is necessary; significant financial commitments are made, and, as a result, location options begin to be foreclosed.

During an engineering survey the detailed bottom profile, sub-bottom stratigraphy, currents, and soils, along with items of special concern such as faults, reefs, rock outcrops, and sand waves are investigated. All of these parameters must be known to properly design the pipeline so that installation will go smoothly and the pipeline will operate safely and successfully throughout its intended lifetime.

Proceeding directly to an engineering survey of the chosen corridor essentially removes the possibility of reducing the macro-level environmental impacts of a pipeline, because they can only be eliminated through siting the pipeline in an environmentally acceptable corridor.

Landfall to Destination: An oil pipeline does not require a wide corridor of land once it comes ashore (nationwide, however, pipelines may be the most land-consuming petroleum activity). The oil pipeline will require a minimum right-of-way between 50 to 100 feet, some of which may be purchased "in fee"; use of other rights-of-way may be obtained by the pipeline company. Gas pipelines require a similar right-of-way. The shore destination--a partial treatment facility or gas processing plant--would be located inland from the landfall site.

Pumping stations are usually required near the landfall site for pipelines transporting oil any appreciable distance. The station could require 40 acres of land and could consist of an office, storage surge tanks, and a pump station. An onshore transfer terminal (for barge transshipment) would require a waterfront location of about 60 acres, with a minimum 35 foot water depth by the frontage land. Another alternative would be to have the oil repiped offshore to a marine terminal where it would be transshipped by tankers [26].

Construction/Installation

Three methods are used for laying offshore pipelines:

1. The method used for most pipelines and for all large diameter pipelines is to weld together 40-foot pipe sections on board a lay barge and continuously lower them over the stern of the barge via a "stringer" to the ocean bottom. As new pipe sections are added, the barge winches itself forward using a sophisticated multi-anchor system.

2. A second method, the reel method, is used for laying small diameter pipelines; traditionally 12 inches or less, but now up to 24 inches. The pipe is welded together onshore, wound onto a large spool, and then later unwound for laying of the pipe. This method is often used for flow lines between platforms.

3. The third method, not widely used, is to weld the pipe into strands ashore, support these strands with floats, and then tow the strands to location. On reaching location, the pipe is flooded and welded onto the main pipeline.

Vessels: Almost all offshore pipelines with the exception of gathering lines between platforms, are constructed using specially built pipe-laying barges and pipe-laying ships. Pipe-laying barges are of numerous types. Traditionally, they have been conventional barges on which a pipe-laying rig was built, but standard ship hulls and semi-submersibles are both in use. In the last few years, as offshore operations have pushed into hostile areas such as the North Sea, pipe-laying barges have grown quite large. One of the more modern barges, Semac, measures 180 feet by 433 feet.

Along with the growth in the size of barges has been a trend toward the construction of semi-submersible barges. Semi-submersibles can better withstand heavy seas. Semi-submersibles can operate in seas approaching 15 feet, whereas operations in a large conventional barge must cease when seas reach 6 to 10 feet. Thus, semi-submersibles have a considerably longer working season than conventional barges.

Coated pipe is brought to the barge in supply boats from a pipe-staging area onshore. Two to three supply boats may be needed to keep the barge supplied with pipe. Under good conditions, over a mile of pipeline can be laid in a day. This is approximately the amount of pipe which can be kept on the deck of the lay barge. Thus, continual resupply from shore must be maintained or pipe-laying operations will come to a halt. This is extremely costly since a lay barge may rent for up to $200,000 per day.

The need for constant resupply means that a staging area will be located as near as possible to the pipeline corridor with deepwater access. Not only will transit distances and time be reduced ,but more importantly the weather window (required period of good weather) for resupply may be greatly reduced. Short runs from the staging area to the barge may even allow resupply during the lull in a storm.

On standard pipe-laying barges, the precoated pipe is put aboard the barge, stacked, and moved joint by joint to the bow of the barge as it enters into the lay system. The pipe ends are inspected for damage, the joints are prepared for welding, each section is aligned with the previous section at the "line-up station." and finally the welds are made. Each successive joint is tested (usually by X-ray); the weld joint is coated with "mastic," synthetic compound or concrete; and then the pipe is launched.

All pipe-laying barges and ships are held in place and moved forward with a multi-anchor mooring system. Most barges have from 12 to 14 anchors. Part of the anchors are being moved forward with anchor-

handling tugs to new positions determined by utilizing the ship's navigation system and its radar, while the remaining anchors hold the barge onsite. Once the new anchors have been set and additional sections of pipe have been welded to the pipeline, the barge is winched forward. Two or three anchor-handling rigs are required to service a pipelaying barge (Figure 19).

The construction of a pipeline is significantly affected by weather and sea conditions. A pipe-laying season may range from 220 to 270 days for large lay barges; but heavy weather conditions may reduce work time to about 40 percent of the laying season (e.g., in the North Sea, where the most efficient barges lay approximately 37 to 50 miles of pipe per year at a rate of 1.24 miles on a good working day [26].

Offshore pipelines are often buried for protection from mechanical damage from currents and waves and from bottom fishing activity and anchoring. A "bury barge" tows a sled which digs a trench by jetting water at high pressure into the ocean bottom (Figure 20). Several passes of the jet sled may be required in order to dig a trench of appropriate depth, depending upon bottom conditions. Currently, Department of Transportation regulations require offshore pipeline burial of 3 feet in water depths less than 200 feet. Offshore gathering lines, which come under the jurisdiction of the USGS do not presently have burial requirements [26].

Construction procedures are different for "the shore approach," or landfall, where neither barges and marine craft nor regular onshore pipe-laying methods can be employed. Most of the generally used methods include opening a trench from shore side to a water depth where barges can operate, fabricating the pipeline string onshore or on the lay barge, pulling the pipeline string into position, refilling and protecting the ditch, and restoring the site. Heavy construction equipment, such as trenchers and large winches, operates at the landfall site to pull pipeline in ecologically fragile areas. Environmental damage from pipeline construction can be partially mitigated by careful construction and restoration techniques.

Pipeline Construction in Wetlands: In the process of moving oil and gas from offshore to upland, an offshore pipeline often must cross through wetland areas. Severe environmental alterations and damage have occurred in wetland crossings. The long canals and resulting berms of spoil left behind have altered water and nutrient flows, thus lowering natural productivity and causing salt water intrusion, loss of wetland habitat, and other problems.

Typical pipeline construction through wetlands is similar to offshore pipe-laying with the exception that the barges are considerably smaller and narrower and that a canal to allow passage of the barge is usually dug using either a cutter head dredge or a dragline in place of the jet sled.

Figure 19. Offshore pipe-laying barge
(Source: Reference 16).

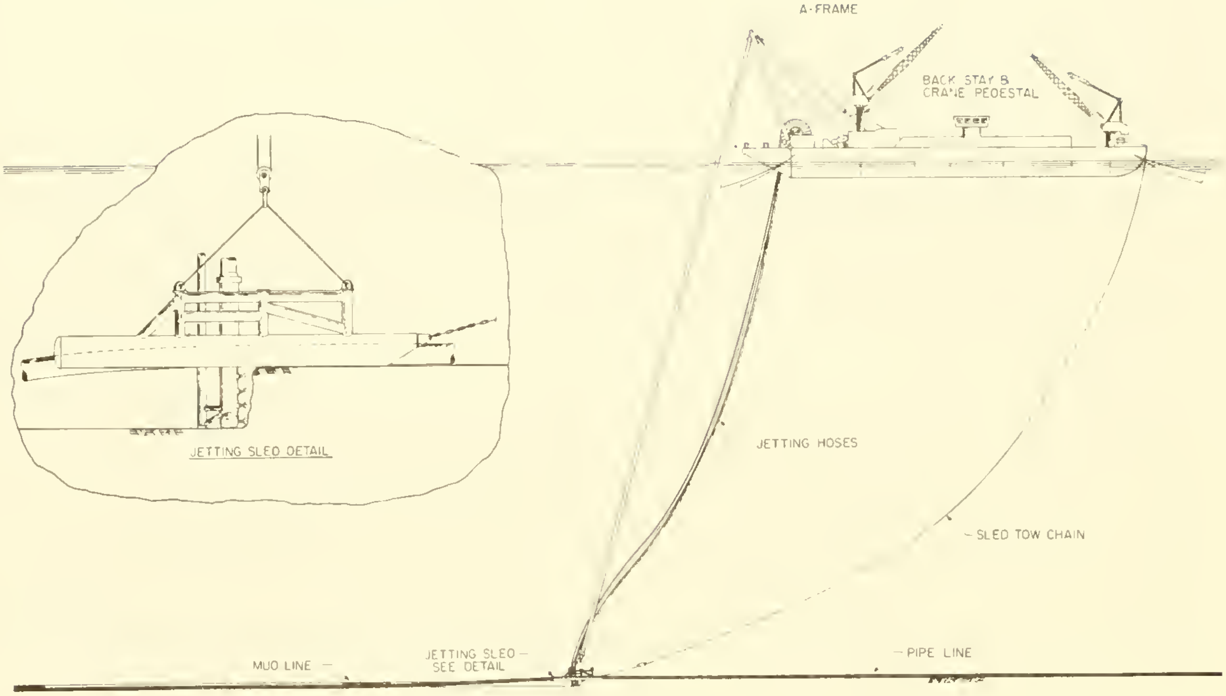
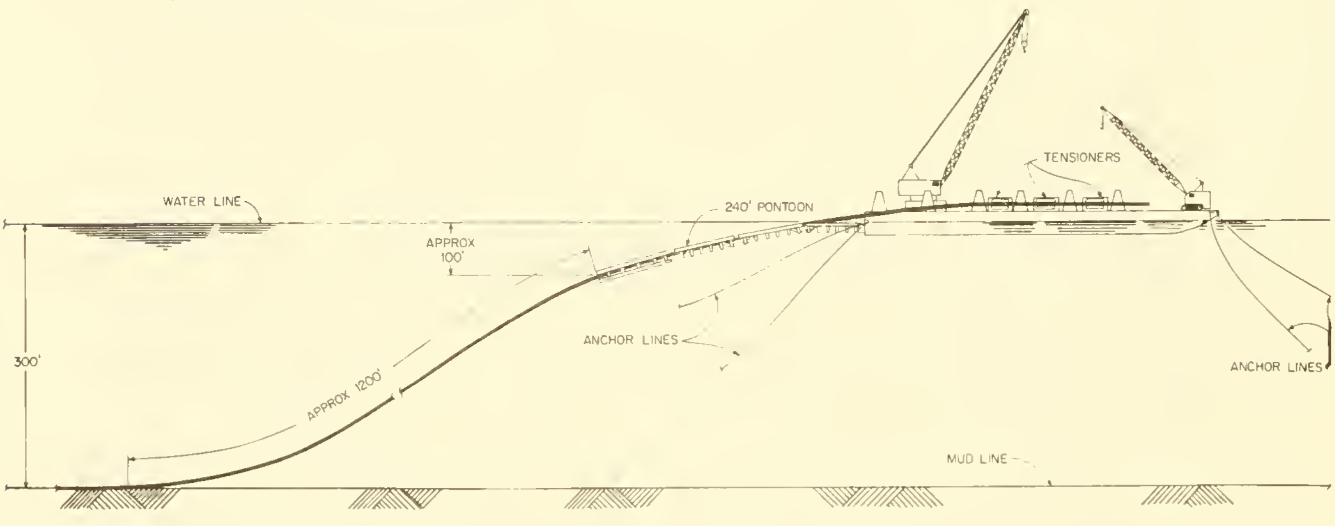


Figure 20. "Bury barge" or pipeline dredge barge.
(Source: Reference 16)



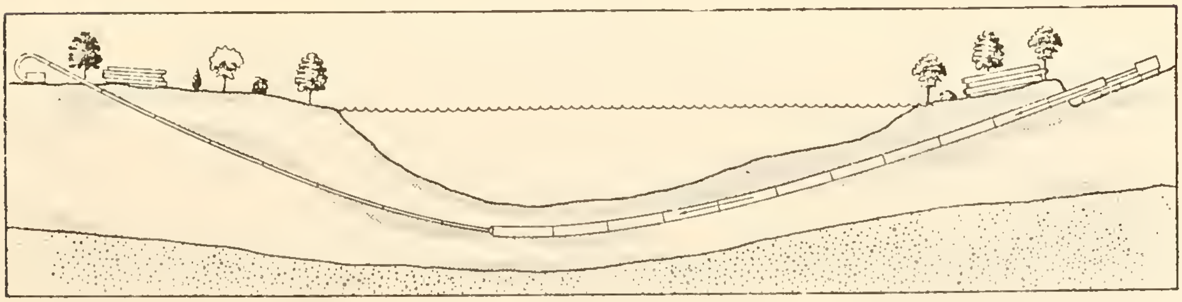
New techniques are now available for laying pipelines in wetlands. One of these, the "push" method, eliminates the need for a pipe-laying barge to enter the wetland; a V-shaped trench is dug through the wetland (the width is dependent on the cohesiveness of the wetland soil). The pipeline is then assembled and pushed ashore from the back of the barge. (The pipeline can also be pulled from the far end with a cable attached to a winch.)

Another new method uses a smaller channel than the traditional method--a canal for a shallow-draft pipe-laying barge is dug with a V-shaped trench in its center. The pipeline is fed into this trench and covered as the barge advances across the wetland.

Onshore Pipelines: Previous sections have dealt with the pipeline from offshore to the "shore destination," the first receiving point--a gas processing plant or an oil transfer terminal or refinery. From this point through the uplands area, the siting and construction of the pipeline is not greatly different from other upland construction. There are also close similarities with power transmission line corridors and utility corridors insofar as the effects on the terrestrial environment are concerned. The following information also applies to the sections from landfall to shore receiving point. From the landfall to the processing plant, refinery, or transfer terminal, the pipeline is of the same dimensions as the pipe coming onshore. It is probably constructed of the same material and may be given a protective wrapping but would not be coated with concrete, thereby having a smaller overall size.

The corridor for onshore sections of the pipeline inland from the shore receiving point will range from about 50 to 75 feet and follow the shortest possible route. It will be buried at a depth of 4 to 6 feet. Pipelines would normally avoid natural obstacles such as lakes or rivers, but where necessary the pipeline may span large rivers or be installed under smaller rivers and streams (Figure 21).

Figure 21. Directional drilling for pipeline installation under rivers and streams (Source: Reference 27).



Operations

Day-to-day operations of pipelines are highly automated and require work forces only for regular monitoring and maintenance.

After installation, pipelines must be monitored periodically. The techniques include monitoring pressure gauges, metering pipeline flow, and surface and air patrols of the routes. Timely leak detection and control of a pipeline necessitate the use of monitoring systems which are "redundant." The main focus of pipeline surveillance is a central control station where the flow rates of the transmission line and of its tributary gathering lines are monitored on a continuous 24-hour basis. Pipelines are currently controlled by radio-activated equipment that can cut off the flow of any part of a line which exhibits low pressures indicative of leaking.

There are two important direct measurement tools that are used for leak detection. One is a pressure sensor that measures pressure reductions. If oil and gas are shipped in the same pipeline, the system will only respond to leaks that cause a pressure decline of at least 30 psi. The second technique measures the volume of flow at two different points on a line and can be used to verify that there has been no loss of oil. If accurate and calibrated instrumentation is used and maintained, this technique is extremely reliable.

A third method for detecting leaks requires the periodic patrolling of the line by surface vessels and aircraft. This surveillance is mandated every two weeks by government regulations. Although this procedure is not an immediate response approach to a major leak, it does provide a means of spotting leaks that may be too insignificant to be picked up by direct measurement sensors.

Community Effects

A pipeline has attributes that may potentially affect a community, depending upon corridor selection. However, with proper planning, such as occurred in Scotland, these effects can be insignificant in onshore communities.

Employment: Offshore, main pipelines are constructed from pipe-laying barges, which employ about 160 to 175 people. Approximately 50 workers would be recruited locally [28]. This operation would lay approximately one mile of pipe per day, and the longest lines would not exceed 200 miles. Gathering lines are usually of much less total length in a field, requiring fewer construction personnel. The length of time required to construct a line depends on factors such as climate and bottom conditions. Pipeline construction offshore will only provide temporary employment in specific skills, such as welding, and is not a likely attractor of new residents.

Onshore, the pipeline installation process is similar to that for a sewer line or water main, employing a similar number of people with heavy equipment to perform similar functions; however, metal pipe is used and must be welded. An estimate of total employment is about 30 to 50 people. Onshore pipe-laying, because of the short time required and because it is an additional contract for a firm already in that business, would not stimulate any significant new employment.

Induced Effects: Pipe-laying will result in minimal effects on the community. Pipe-laying barge workers will travel home or spend brief periods of time in local temporary residences. However, with proper environmental safeguards implemented during construction (except under localized and temporary circumstances), the scale and character of these pipe-laying activities have little significance for the local community and its natural resources. More significant impacts will come from the associated pipe coating yards (Section 2.3.5) and service bases (Section 2.3.1).

Pipe-laying companies tend to permanently employ their skilled workers who travel from contract to contract with the barge. They do, however, hire local labor to fill crew needs. A pipe-laying barge, by the nature of its work, is only intermittently employed. Between contracts, the boat is usually berthed in the nearest harbor or where necessary repairs can be made. Most permanent crew members travel home, and only a skeleton group remains to maintain the vessel and equipment. Their presence should not affect the local economy to any degree.

Effects on Living Resources

An oil or gas pipeline, either offshore or onshore, has the following characteristics of particular concern to fish and wildlife resources: (1) underwater excavation; (2) subsea or terrestrial burial; (3) corridor routing; (4) pumping stations; (5) landfall construction; and (6) crossing sensitive habitats.

Location: In planning an oil or gas pipeline the sponsor tries to locate the line along the shortest route, avoid rocky areas, and have as much of the pipe on land as possible. Location will involve traversing the ocean bottom, a landfall at a beach or wetland, and traveling across land to a refinery or gas processing plant.

The sponsor must give considerable attention to environmental constraints, particularly those affecting coastal ecosystems, because construction of pipelines normally requires underwater dredging. The underwater excavation is usually accomplished by a hydraulic "jet-sled" which creates a liquid slurry of bottom materials allowing the pipe to sink into the trench created. Excavated material is deposited beside the trench and refilling of the trench is left to water currents and sedimentation. Improper burial may leave the pipeline exposed and

vulnerable to fishing gear or anchors which may rupture the line causing an oil or gas leak.

Corridor siting is of vital concern to fish and wildlife, because pipeline construction through the habitat, especially in wetlands, may bisect the area. This may create changes in the water circulation patterns, salinity, temperature, or other parameters whose stability is necessary to the survival of various species in the area.

Design: The high potential for adverse aquatic impacts of the nearshore and landfall location requires that the sponsor exert maximum care in design of the landfall, including provisions for: (1) maintaining the natural shoreline; (2) minimizing dredging; (3) arranging proper disposal of spoil; (4) avoiding wetlands; (5) reducing problems of runoff discharge; (6) backfilling; (7) maintaining tidal exchange; (8) restoring vegetation; and (9) construction and maintenance of bulkheads or pilings at all crossing of natural tidal creeks and rivers. Roadway and maintenance corridors should follow the same precautions.

Construction: The sponsor must perform the terrestrial construction with the utmost care to protect adjacent aquatic and terrestrial areas. The scheduling of construction must avoid sensitive annual periods of species, including breeding/spawning, rearing of young, etc. Operation of heavy equipment must be performed to protect fragile environments, such as barrier beaches, wetlands, and productive shallow flats. In many cases, especially in landfall areas, mats can reduce the impact of heavy equipment operations and access to construction sites can be accomplished by existing service roads.

Dredging of pipeline trenches in coastal areas should be done in a manner which will minimize turbidity and sedimentation, such as sediment-screen employment and other techniques. If pipeline trenches are dug through wetlands, excavated material should be replaced in the trench instead of along the sides where it can interrupt water flow and change circulation patterns. In addition, new fill material should be added where necessary to keep the elevation of the trenched area the same as the surrounding wetland.

Terrestrial crossings require that special care be taken to reduce effects on wildlife and endangered species, their habitats, and the fresh-water system. A major factor is prevention of erosion and sedimentation into local streams and rivers where fish habitats could be adversely affected. River crossings can be particularly complicated and can yield unnecessary impacts to downstream areas. Use of the subterranean drilling method virtually eliminates disturbances. As part of the construction, a restoration program should be instituted to revegetate the excavated areas as soon as possible. Temporary stockpiling of dredged material from trench construction should not be on river bottoms or productive riverine habitats.

Operations: The sponsor's major environmental concern in the operation of a pipeline will be the prevention of pipeline rupture and subsequent oil spills.

Normally, problems associated with the pipeline corridor are by far the most important consideration affecting fish and wildlife resources and the one consideration that the applicant will have to give the most effort to solving. Designing the landfall to avoid shoreline disturbances, particularly of wetlands, will be next in importance. Requirements for terrestrial construction and operations will likely come next. However, depending upon the locale and other specifics, the priority of the above may change dramatically.

Regulatory Factors

The pipeline contractor seeks to minimize the onshore and offshore environmental impacts of the placement of the pipeline by choosing an environmentally acceptable corridor as the site. The location of the pipeline may ultimately depend upon the sites selected for any natural gas processing plant (discussed in 2.4.3) or refinery (discussed in 2.4.1) or the location may depend on existing onshore pipeline distribution systems.

The oil and gas company and pipeline contractor must consider both state and Federal permits and sometimes other local regulatory requirements before choosing a corridor.

State and Local Role: Responsible state and local entities may seek to minimize onshore impacts of pipeline construction by requiring the contractor to employ new techniques for laying pipelines, especially in wetlands. States may do this under siting laws which apply in addition to required Federal permits. The contractor may need to obtain state permits and certification for related construction activities as well.

State jurisdiction over the siting of any pipeline ends at the limits of the state's territorial waters (three miles, except for three leagues off Texas and Florida Gulf Coast).

Federal Role: Dredging and filling in navigable waters of the United States require permits from the Corps of Engineers authorized respectively under Section 10 of the River and Harbors Act of 1899, and Section 404 of the Federal Water Pollution Control Act Amendments of 1972. The FWS reviews these permit applications under the Fish and Wildlife Coordination Act and NEPA. The Service seeks to protect fish and wildlife and their habitats, especially those of endangered species. A sponsor would also need to obtain an easement for a right-of-way for pipelines, either from BLM for lines from lease tracts to shore or over

Federal lands, from USGS for gathering lines within a field, from state in state waters, or from private owners along a proposed right-of-way. The Federal Power Commission issues certificates for construction and operation of gas transmission lines (Table 11).

Gas pipelines are also subject to Federal safety standards described in 49 Code of Federal Regulations. They are promulgated under the Natural Gas Pipeline Safety Act (NGPSA), and govern the design, construction, operation, and maintenance of gas pipeline facilities and the transportation of gas in or affecting interstate or foreign commerce. These safety standards apply to gas pipeline facilities and to the transportation of gas in its liquid or gaseous state onshore, on lands beneath navigable waters, and on the Outer Continental Shelf. The Office of Pipeline Safety (Materials Transportation Bureau), Department of Transportation, implements and enforces these regulations.

Offshore gathering lines are now regulated primarily by USGS under lease area development plans. A Memorandum of Understanding between the Departments of Interior and Transportation, published on June 11, 1976, in Volume 41 of the Federal Register, page 23746, clarifies the regulation of offshore gathering lines. The Materials Transportation Bureau in the Department of Transportation has proposed to amend 49 Code of Federal Regulations, Part 192.1 to expand that Part's coverage of offshore gathering lines. The authority for the proposed regulation is the Hazardous Materials Transportation Act, which includes gas pipelines which are not subject to the jurisdiction of the NGPSA.

Development Strategies

Numerous alternatives for the transportation of oil and gas are available.

When the existence of a commercial oil field is established, a decision must be made on the best method of transporting the oil to shore. The oil can be transported either by pipeline or by bulk carrier, such as an oil tanker or barge. Evaluation of many variables is required in order to optimize the transportation scheme. Among these variables are oceanographic and meteorological conditions affecting tanker operations, volume of oil to be transported, and distance from refining areas [26]. Economics will principally decide which option of many is chosen. In some cases, barge or tanker transport will be used initially. Later, a pipeline may be built after production from the field and nearby fields passes the threshold value which can economically justify its construction.

Alternatives: Among the alternatives for transporting oil and gas are the following:

Table 11. Regulatory Responsibilities for Pipelines (Source: Adapted from Reference 20)

TYPE OF PIPELINE / FUNCTIONAL AREA	SITING	EMISSIONS AND EFFLUENTS (E/E)	PUBLIC SAFETY	WORKER HEALTH AND SAFETY	RATE MAKING	ABANDONMENT
OFFSHORE	BLM: GRANTS RIGHT-OF-WAY PERMITS FOR GAS AND OIL PIPELINES FWS: COMMENTS-S.O. 2974	BLM: INCLUDES STIPULATIONS FOR E/E AS CONDITIONS FOR GRANTING RIGHT-OF-WAY	BLM INCLUDES PUBLIC SAFETY STIPULATIONS AS CONDITIONS FOR GRANTING RIGHT-OF-WAY PERMITS	OSHA ESTABLISHES AND ENFORCES WORKER HEALTH AND SAFETY REGULATIONS	FPC: REVIEWS GAS TRANSMISSION RATES AND GAS PRICES FOR OPERATIONAL GAS PIPELINES	FPC: GRANTS APPROVAL OF ABANDONMENT OF OFFSHORE NATURAL GAS PIPELINES
	USGS. REVIEWS PERMITS APPLICATIONS SUBMITTED TO BLM FWS: COMMENTS – S.O. 2974	FPC INCLUDES STIPULATIONS FOR E/E AS CONDITIONS FOR GRANTING CERTIFICATES	FPC: INCLUDES PUBLIC SAFETY STIPULATIONS AS CONDITIONS FOR GRANTING CERTIFICATES		ICC: GRANTS APPROVAL OF THE TARIFF RATES FOR TRANSPORTATION OF OIL BY COMMON CARRIER PIPELINES	(NO PERMIT REQUIRED FROM ICC FOR ABANDONMENT OF OIL PIPELINE)
	FPC: ISSUES CERTIFICATES FOR CONSTRUCTION AND OPERATION OF OFFSHORE GAS TRANSMISSION LINES	COE ISSUES PERMITS AND ENFORCES REGULATIONS REGARDING DISPOSAL OF DREDGED OR FILL MATERIAL	CG: ISSUES AND ENFORCES REGULATIONS CONCERNING CLEANUP OF OIL DISCHARGES AND PLANS FOR HANDLING FIRES THAT MIGHT RESULT FROM BREAKS IN OIL AND GAS PIPELINES			
	COE: ISSUES PERMITS FOR ACTIVITIES IN OR AFFECTING NAVIGABLE WATERS	FWS: RECOMMENDS STIPULATIONS TO BE INCLUDED IN COE PERMIT	OPS: ISSUES AND ENFORCES REGULATIONS PERTAINING TO DESIGN AND CONSTRUCTION FOR OIL AND GAS PIPELINES			
	FSW, NOAA, NMFS REVIEW APPLICATION BEFORE COE DECIDES ON THE ISSUANCE OF A PERMIT	CG: ENFORCES AND ESTABLISHES REGULATIONS CONCERNING PREVENTION AND CLEANUP OF DISCHARGES FROM PIPELINES	NTSB: INVESTIGATES AND PREPARES REPORTS ON ACCIDENTS AFFECTING OFF-SHORE OIL AND GAS PIPELINES INVOLVED IN INTERSTATE COMMERCE			
		OPS: ISSUES AND ENFORCES REGULATIONS DESIGNED TO PREVENT E/E FROM PIPELINES				

(Continued)

Table 11. Continued

FUNCTIONAL AREA / TYPE OF PIPELINE	SITING	EMISSIONS AND EFFLUENTS (E/E)	PUBLIC SAFETY	WORKER HEALTH AND SAFETY	RATE MAKING	ABANDONMENT
ONSHORE	BLM GRANTS RIGHT-OF-WAY PERMITS FOR GAS AND OIL PIPELINES	BLM SAA	BLM SAA	OSHA SAA	FPC SAA	
	FPC ISSUES CERTIFICATES FOR CONSTRUCTION AND OPERATION OF GAS TRANSMISSION LINES	FPC. SAA	FPC SAA		ICC SAA	
	COE. ISSUES PERMITS FOR ACTIVITIES IN OR AFFECTING NAVIGABLE WATERS	COE SAA FWS. SAA OPS SAA	OPS: ISSUES AND ENFORCES REGULATIONS PERTAINING TO DESIGN AND CONSTRUCTION FOR OIL AND GAS PIPELINES ALSO ISSUES AND ENFORCES REGULATIONS PERTAINING TO THE PIPELINE TRANSPORTATION OF HAZARDOUS MATERIALS AND PETROLEUM PRODUCTS BY CARRIERS ENGAGED IN INTERSTATE COMMERCE			
	FWS, NOAA, NMFS REVIEW APPLICATION BEFORE COE DECIDES ON THE ISSUANCE OF A PERMIT	EPA IS CONCERNED WITH PIPELINE ASSOCIATED FACILITIES AND NOT THE PIPELINE ITSELF. FOR PUMPING STATIONS AND TERMINALS, EPA ISSUES WATER DISCHARGE PERMITS AIR EMISSIONS FROM PUMPING STATIONS ARE CONTROLLED BY STATES AND EPA				

SAA = SAME AS ABOVE

1. As oil is produced, it is pumped immediately to shore through a pipeline: onshore the oil can be (1) pumped through pipelines to refining centers, or (2) stored in large tanks at a transshipment terminal where it will be pumped onto tankers for transport to distant refining centers.

2. The oil can be pumped to a central offshore storage tank from which tankers transport the oil to refineries; the oil is transferred from the tank to tankers via a "single point mooring system." (Section 2.2.5)

3. The oil is stored in large tanks within the platform's base from which it is loaded via a "single-point mooring system" onto tankers.

4. The oil is pumped from the platform directly through a "single-point mooring system" to a tanker; when the tanker is filled, it departs and another takes its place (this method has serious storage and cost problems and is unlikely to be used).

5. Oil is pumped from the platform onto a "ship-shape" barge attached to a "single-point mooring system"; the oil is transported to shore by transferring the oil from the barge to tankers shuttling to refineries.

Bulk carriers have a higher environmental risk than pipelines and are not usually an economically attractive substitute for pipeline transportation, if sufficient quantities of oil are available to satisfy pipeline construction. Offshore loading facilities are required as well as storage facilities to handle the oil produced while bulk carriers are not loading. Transportation via bulk carriers is subject to interruption by bad weather which may necessitate shutdown of production and interruption of supply. These factors discourage usage of bulk carriers. There is, however, currently a surplus of tankers, and operators may be reluctant to use pipelines unless there is a large cost-offset. Tankers also provide flexibility.

There are considerably fewer alternatives for the transport of gas to consumption centers. This is largely because gas is such a high-volume to value commodity. Its volume can be reduced in order to reduce its cost of transport, but costs are incurred in processing to reduce volume. The ship alternative requires the gas to be liquefied prior to shipment by a process using very low temperatures. This requirement, together with the special carriers needed to move the liquefied natural gas (LNG) greatly increases capital cost. The result is that pipelines

are preferred. If gas is not of sufficient quality to justify pipeline, it is put back into the structure to increase oil recovery or, if not useful, flared.

Investment Tradeoffs

If the offshore oil reserves are large a pipeline will almost assuredly be constructed. If the field is far offshore and remote from other oil fields, a pipeline may not be possible and alternatives 2 to 5 (described above) will be given careful consideration. The economics of using tankers for floating offshore storage tanks have improved enormously during the past six years due to improvement in design and construction of these offshore storage facilities. Alternative two is additionally attractive if the oil stream arriving from offshore were to be split, some being refined in the adjacent region and the rest being transported elsewhere for refining.

Unless an offshore gas field is large enough or near enough to shore to justify a pipeline to shore and from there to consumption centers, it will probably not be developed. Liquefaction of gas to reduce its volume for transport is expensive,and probably prohibitively so,when done offshore. Development of an offshore gas field becomes slightly more feasible if a pipeline from offshore to an onshore liquefaction plant can be justified, but the associated capital costs may also preclude development. In the North Sea, every gas field which has been developed is piping its gas, not to the nearest onshore location for liquefaction and shipment, but considerably farther to demand centers in England and Germany.

The determination of the proper diameter for an offshore pipeline involve economic tradeoffs between the cost of pipe, the feasibility and cost of erecting interim booster pumping platforms offshore, and the cost of operating pumping stations. A given pipeline can handle greater volumes of oil or gas if more and larger horsepower pumping stations are added along the pipeline route.

Corridor selection is made so as to minimize the total cost and logistical difficulties involves in constructing and operating an entire oil transport system. Therefore, it is important that the selection of a pipeline corridor be evaluated in the context of its full potential impact on an area.

The selection of a pipeline corridor is often considered simultaneously with the selection of a site for an oil transfer terminal and, to a lesser extent, the onshore support base (including materials staging) for the construction of the pipeline. Decisions as to the acceptability of the corridor must be made on the basis of the whole range of impacts and changes the corridor will induce during its construction and operational lifespan.

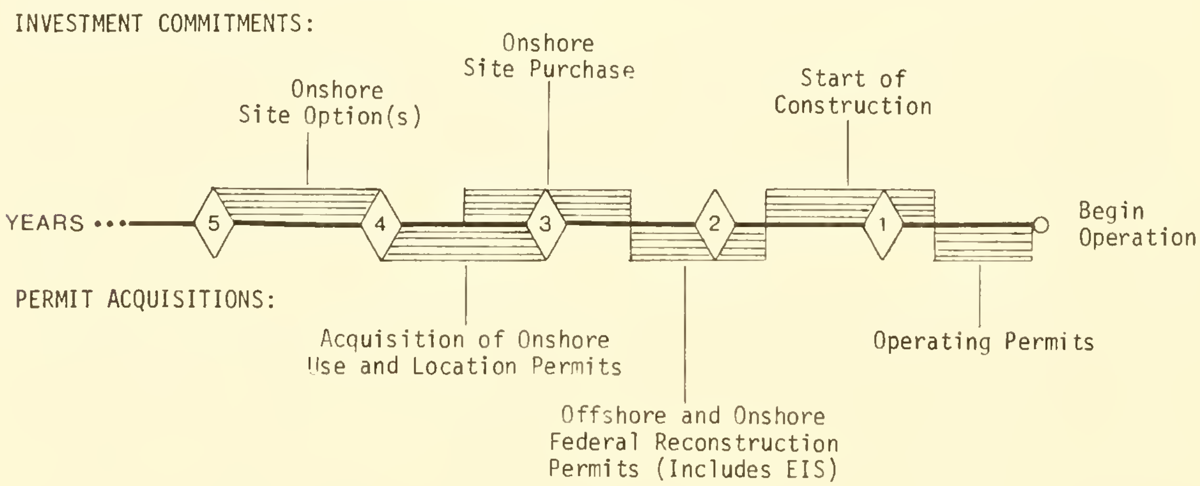
During site selection, great flexibility exists in locating facilities to mitigate environmental impacts especially in remote areas such as Alaska. For instance, if commercial quantities of oil were found in Lower Cook Inlet, a pipeline could be built to onshore facilities on either side of the inlet. The western shore of Cook Inlet is a wilderness area where environmental impact would be highest; whereas, the lightly populated eastern shore which has roads and some community infrastructure would be less environmentally harmed.

Onshore development in a wilderness would probably cause far more significant impacts over the long term than would development in an urban area or even a rural area.

2.2.5 Offshore Mooring and Tanker Operations

Transportation of petroleum, when fields and markets are separated by water, is often done by tankers. As tankers have increased in size, new systems for transferring petroleum between vessel and shore point have been devised. The increased draft of tankers has made fewer ports available for landing and for direct transfer into shore storage terminals. A technological response to this need has been offshore mooring systems, termed single point mooring (SPM), which are connected to storage terminals by pipelines (see Figure 22). SPM related problems with tankers are discussed along with other regular problems of tankers used in international and national transport of petroleum products from port to port.

Figure 22. Offshore mooring - project implementation schedule.



When located at sufficient depths, single point moorings eliminate the need for deepening existing harbors, channels or turning basins, future maintenance dredging or the extension of existing piers. The SPM is anchored to the seabed and the tanker moves freely around the mooring to a position of least resistance to wind, waves and currents. This enables a tanker to remain moored in relatively severe weather conditions.

SPM systems may be a practical, and environmentally acceptable, alternative to traditional port facilities for transferring cargoes between the shore and Very Large Crude Carriers (VLCC) and Supertankers. While more than 150 SPM's are operating in oil producing and consuming areas around the world, none have yet been installed in the United States.

Several SPM Systems are planned for the United States. We rely on overseas supplies of crude oil for over 40 percent of our needs. With approximately 65 percent of the world's known producible oil reserves located in the Middle Eastern and African nations, VLCC's, which range in size from 160,000 DWT (dead weight tons) to 500,000 DWT, represent the most economical means of transporting large volumes of crude oil over large distances. The majority of U.S. harbors, however, are currently unable to receive VLCC's. The controlling depth of U.S. harbors, except for Puget Sound and the Virgin Islands, is 52 feet or less which precludes all VLCC's larger than 160,000 DWT [29]. Figure 23 illustrates channel depths for major oil terminal ports in the United States.

SPM's are planned for two offshore "ports" on the Gulf Coast, LOOP (Louisiana Offshore Oil Port) located 18 miles south of Grand Isle, Louisiana, and "Seadock," 26 miles south of Freeport, Texas. Another SPM is contemplated as part of the development of the Santa Ynez field near Santa Barbara, California.

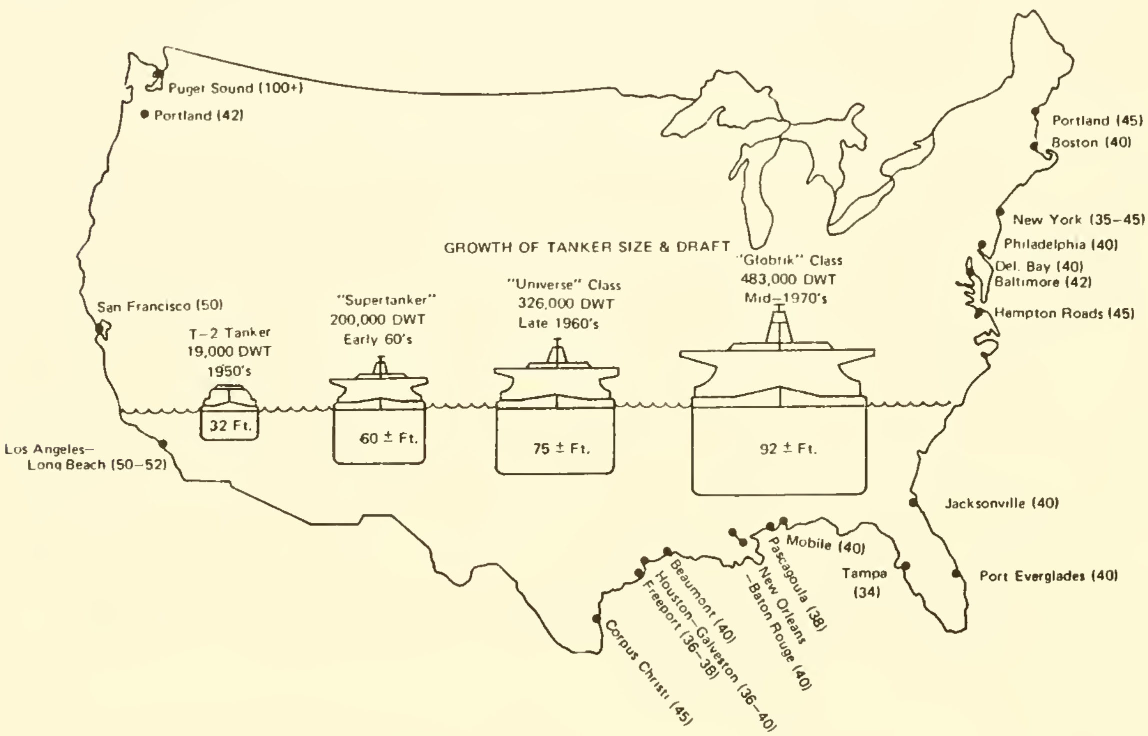
Description

SPM: these are floating mooring systems located offshore in water depths of 50 to 150 feet. A tanker is moored to the SPM by lines, or a rigid yoke, connecting its bow to a buoy or tower structure floating on the surface. Oil can be transferred to and from onshore and offshore storage tanks by submarine pipelines connected to the SPM and the VLCC. Vessels usually can be moored at SPM's without the aid of tugs. Oil can be pumped by onshore pumping stations, offshore pumping platforms or by the VLCC itself. Offshore pumping platforms are constructed either when SPM's are located a considerable distance offshore or when high pumping rates are required (Figure 24).

There are two types of SPM systems in widespread use: the Catenary Anchor Leg Mooring (CALM) and the Single Anchor Leg Mooring (SALM).

Both allow the attachment of mooring lines from the bow of the ULCC to a swivel on a mooring buoy which is attached to the sea bottom. The mooring buoys are equipped with safety lights, bells and fog horns to reduce the chances of damage and are designed to withstand considerable impacts.

Figure 23. Controlling water depths (feet) at major United States ports (Source: Reference 29).



The CALM system (Figure 25) was developed by the Offshore Marine Terminal Company and the cylindrical, steel buoy has a diameter of 30 to 50 feet. Pre-stressed catenary chain legs anchor the buoy to piles fixed to the sea floor. A CALM system is placed in depths ranging from 50 to 120 feet depending on the draft of the largest VLCC to be served [26].

The SALM system (Figure 26) consists of a cylindrical steel buoy approximately 13 feet in diameter and 56 feet high, attached by an anchor chain to a single mooring base fixed to the sea floor. The mooring buoy has an upper chamber available for storage and a lower ballast chamber [26].

Figure 24. Simplified schematic of offshore facilities single point mooring system (Source: Reference 30).

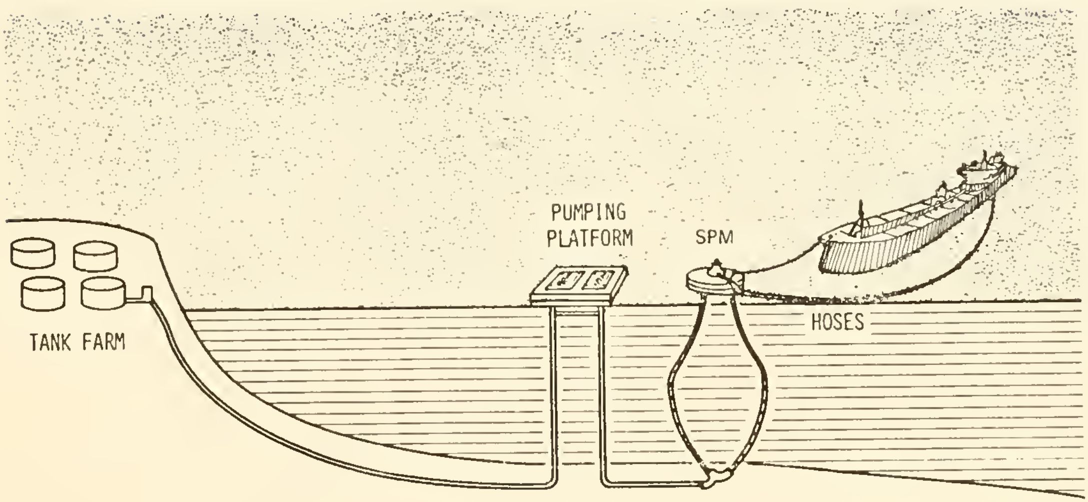


Figure 25. Catenary Anchor Leg System (CALM) (Source: Reference 26).

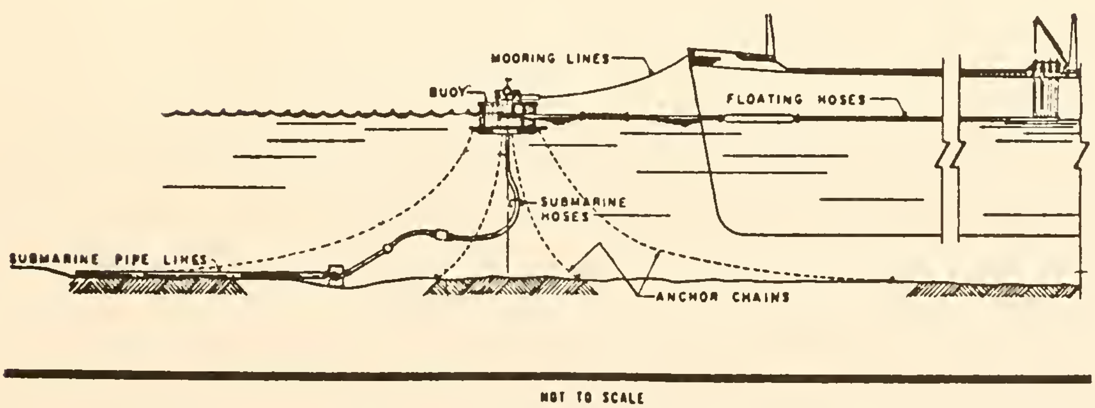
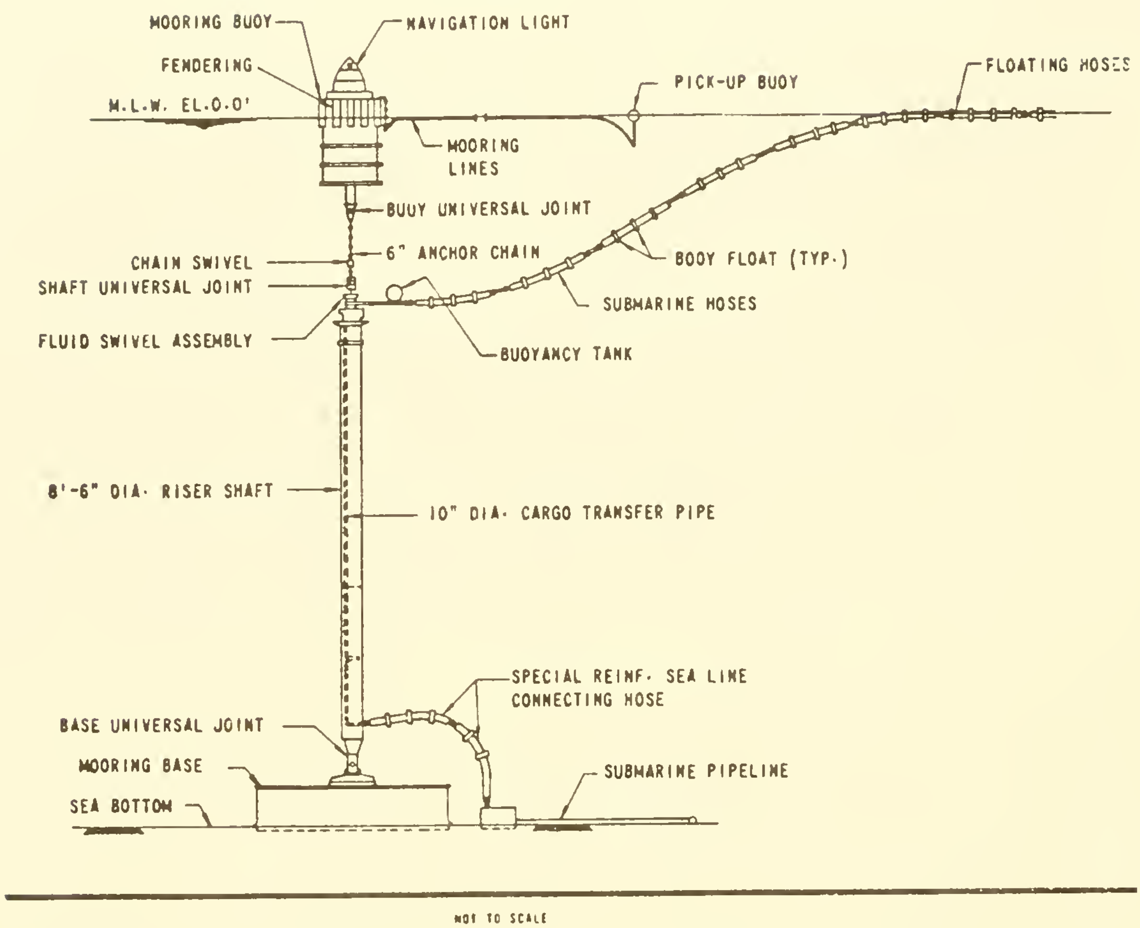


Figure 26. Single Anchor Leg Mooring (SALM)
(Source: Reference 26).



Tankers: the modern tanker is a highly developed and specialized ship type designed to transport various kinds of liquid cargoes. Normally, a tanker is designated to carry either a "clean" (product) or "black" (crude) oil. The "clean" oils are aviation fuel, gasoline, kerosene, gas oil, high speed diesel oil, gas turbine oil, to name a few; while the "black" oils consist of crude oil, and residual oils. "Clean" oils are usually carried in the smaller ships, the bulk of their work being of a short haul coastal service while the 'black" oils are carried in the larger ships, their work being more of a long haul nature from the oil wells to the refineries.

Site Requirements

The ideal location for an offshore mooring would be a nearshore area protected from strong winds, waves and currents, with a natural water depth greater than the draft of the largest vessel expected during the life of the project. All SPM's are located where the sea floor geology is stable and capable of anchoring the SPM firmly in place.

A major siting criterion is the route of the submarine pipeline, landfall, and onshore pipeline or terminal. Considerations for pipeline siting are discussed in Section 2.4.2.

SPM's are most commonly found in newer oil areas in foreign countries where other deep water port facilities are impractical or economically infeasible. In older producing and market areas, such as the United States, SPM's may be built to serve existing or proposed oil and gas related facilities. They will be located near pipelines and storage terminals, and to a lesser extent, refineries. The siting of oil storage terminals is presented in Section 2.3.6, and that of refineries in Section 2.4.3.

Construction/Installation

Both tankers and SPM's are fabricated at shipyards. Conventional equipment is used and construction activities introduce no major disturbances to the area. Installation of the SPM requires support tugs, supply ships and a derrick barge for driving the piles that attach the SPM base to the sea floor. Installation of the SPM itself is relatively uncomplicated and has little ecologic impact. Critical submarine pipe laying and burial are covered in Section 2.2.3.

Operations

SPM: oil is loaded and unloaded through a pipeline and floating hose attached to the vessel's manifold. CALM systems have been built with multi-purpose manifolds and floating hoses to facilitate several operations simultaneously, such as refueling and crude oil transfer. After the transfer of fluids, the floating hoses retract to the buoy. The oil being transferred in a SALM system is pumped through a floating hose, a pipe within the anchor leg and the submarine pipe to an onshore storage tank.

A sophisticated monitoring system safeguards unloading and loading activities. Regular inspections are scheduled to check the structural stability of the entire SPM system and pipelines to sufficiently protect against ruptures and leakage.

Tankers: Tank cleaning and deballasting operations are environmentally harmful. Tank cleaning is required when:

1. A cargo is to be carried which will not tolerate residues from a previous cargo.

2. A vessel is to undergo repair work which by its nature requires gas free conditions.

3. Clean ballast is to be taken on board.

Previous to the development of the large super-tanker, the prevailing custom was to clean all tanks, the object being to prepare the vessel to carry a different cargo. A tanker will generally operate with as many full tanks as possible, depending on the density of the oil, on one leg of its voyage and will return with ballast water in certain tanks,that if no commercial cargo is available, insure that the vessel is seaworthy and capable of safe navigation [31].

The quantity of ballast water taken on is large, sometimes as much as fifty percent of the loaded deadweight tonnage. The actual amount and disposition of this ballast will depend upon the following factors [31]: (1) stability and trim, (2) propeller immersion, (3) machinery vibration avoidance, (4) length of voyage, (5) hull stresses, (6) steering characteristics, and (7) sea state.

A normal ballasting procedure is as follows: the vessel upon discharge of its oil, takes on ballast water either at the dock or immediately upon departure. This water is placed in uncleaned empty oil tanks according to an optimum profile plan as indicated by the above factors. Upon departure, the crew embarks on the tank cleaning operation of the still empty tank in preparation for taking clean ballast on board. After certain tanks are cleaned, they are filled with clean ballast and the dirty ballast tanks are then emptied by pumping overboard. The reason for this is that the discharge of dirty ballast water is prohibited in coastal areas by either international or local pollution laws, therefore if a vessel is to maintain its seaworthiness for the entire length of the voyage, it must be in a position to de-ballast only clean water while coming into port [31].

The actual mechanics of the tank cleaning operation are accomplished by spraying cold or heated high pressure sea water into the cargo tanks through tank cleaning heads. Upon completion of the operation, the clean tanks are filled with sea water while the dirty tanks are pumped dry. Cleaning water sprayed into the dirty tanks will dislodge much of the oil adhering to structural members and, if directly pumped overboard, will result in significant discharges of oil. At present, this practice has been restricted by recent legislation limiting the quantities of oil pumped overboard. Reliable sources indicate that the amount of oil left as clingage in cargo tanks is

approximately 0.4 percent of the cargo deadweight. In addition, considerable amounts of oil may remain in cargo tanks after cargo pumping operations as a result of plugged limber holes and the resulting poor drainage past structural members [31].

The recent "load on top" technique reduces the amount of oil discharge to within the permissible limits of the present law. This technique consists of pumping the oil residue from the tank cleaning operation into an empty cargo tank. This mixture is then allowed to separate by gravity (the oil normally is on top since its density is usually less). Water is pumped overboard until the interface approaches the suction line. The remaining fluid is a mixture of about 75 percent oil, 25 percent water. This is transferred to a cargo tank in which new oil is loaded on top. In the event that the new oil is of a different type, then additional measures must be taken such as pumping the fluid ashore or using it as fuel in the vessel's propulsion system after further separation.

The problems associated with this system relate more to practical application than to theory. Analysis of this technique indicated that effective oil/water separation may be adversely influenced by the following [31]: (1) severe sea state conditions; (2) insufficient separation periods due to short voyage (one tanker operator recommends 10 to 12 hours); (3) agitation due to the pumping operation itself; (4) cargo oil having a specific gravity close to sea water; (5) inaccurate overboard discharge measuring devices; and (6) human error.

Community

Moorings are located offshore and require limited onshore coastal facilities, making small increases in demand on public facilities. In the United States, SPM's are anticipated in locations where onshore facilities, including tank farms, pipelines, and refineries are already in place. SPM's merely offer a less expensive way to transfer crude.

Employment: During construction, an average total work force of less than 1,000 will be employed at each of the two proposed offshore terminals (LOOP and Seadock), peaking at approximately 1,500. A majority of the labor force will be employed in fabricating and installing offshore facilities, and will not affect local communities. A smaller work force, up to 380 workers, will construct the onshore facilities, including docks, warehouse and terminal facilities. Established contractors and a local labor force should conduct a majority of this onshore work.

Employment upon completion is estimated at 300 workers to maintain, operate and monitor the facilities [29, 30].

Induced Effects: Demand for services at the facility and by new residents will strain a local economy in a rural region. In addition,

if the large offshore work force comes onshore during non-work periods, their demands for services could extend local facilities. A majority of the fabrication work will be completed in established fabricating facilities and should not affect the adjacent onshore community. Operations will have more substantial effects, but the scale will depend upon the number of new residents attracted to the area. Total effects will be tied into the additional industry and services attracted to the local area by the presence of this facility.

Effects on Living Systems

An SPM has the following characteristics of particular concern to fish and wildlife personnel: (1) oil transfer from Very Large Crude Carriers (VLCC); (2) pipeline to shore; (3) oil storage terminal; and (4) pumping platform. Normally, problems associated with selecting the pipeline corridor are the most important consideration affecting fish and wildlife resources, and the one that the sponsor will have to give the most effort to solving. The sponsor of the single point mooring can be expected to route a pipeline with the shortest distance to the storage terminal area. However, depending upon several factors, a longer pipeline route may be selected. These decisions may be made to reduce the possibility of oil spills and their impact on fish and wildlife.

Location: In the United States, the SPM has been proposed with a highly specialized function of unloading crude oil from VLCC's. To accommodate such large draft vessels, deepwater sites are sought as close to shore as possible to minimize underwater pipeline construction costs. To reduce the chance of collision,SPM sites should not be in or near regular shipping lanes. Desirable locations, where a vessel can anchor sheltered from the weather, exist only in a few places around the United States. Prevailing winds and oceanic currents will have to be considered in siting a single point mooring to avoid locations where there would be a high risk of an accidental oil spill coming ashore.

Design: With the need to service VLCC's, the selected deepwater site will need ample space to allow manuevering of the large ships including turn-around capability. To reduce the chance of an accidental oil spill a highly reliable transfer system should be employed to keep human error to a minimum. A sophisticated monitoring system, which not only records unloading operations, but gives indications of possible trouble sources should be incorporated into the design.

The pipeline from the single point mooring to the onshore oil terminal will have to be buried to avoid possible rupture and oil leaks from fishing gear, dragged anchors, etc. Automatic safety valves at the mooring, at the oil terminal, and perhaps between those points will have to be installed to minimize the effects of accidentally spilled oil.

Construction: With the need to lay a pipeline to shore, most of the environmental impacts will arise from the dredging needed to bury the pipeline. (Section 2.2.4) Dredging of pipeline trenches, especially in coastal areas should be done in a manner which will minimize turbidity and sedimentation (such as the employment of sediment screens and other techniques). If pipeline trenches are dug through wetlands, excavated material should normally be replaced in the trench instead of diked along the sides where it can interrupt water flow and change circulation patterns, salinity, temperature and other factors. Also, fill material should be added incrementally where necessary, not all at once, in order to keep the elevation above the pipeline the same as that of the surrounding wetlands.

Operation; The major environmental problem in SPM and tanker operation will be in meeting pollutant discharge standards on waste disposal and oil discharge. Constant supervision and contact will have to be maintained between the single point mooring buoy and the oil tanker to ensure proper and safe transfer.

The possibility of tanker damage and oil spill are significantly reduced if single point moorings can be situated where navigational hazards (such as rock outcrops) are absent. Most oil spilled into water initially floats at the water surface. Wind and water forces effectively distribute spilled petroleum hydrocarbons into all components of the marine and coastal environment, including the water column, sediments, atmosphere, and the organisms present in the marine and coastal ecosystems.

Wildlife that comes in contact with an oil spill can be harmed or die from ingestion of petroleum, or can lose the insulating capacity of their feathers or fur. Generally, fish are able to avoid the effects of an oil spill because they swim beneath it, but aquatic birds present other problems. Some diving birds that fully submerge are mostly unable to walk on land and are virtually restricted to the aquatic medium. Oil spills have drastic implications to oceanic birds which are found to the aquatic medium.

In addition to direct kills of organisms, the major adverse environmental effects of direct oil pollution of coastal waters are: (1) disruption of physiological and behavioral patterns of feeding and reproductive activities of aquatic species, (2) changes in physical and chemical habitat, causing exclusion of species and reduction of populations; and (3) stresses on the ecosystem from decomposition of refinery effluents resulting in altered productivity, metabolism, system structure and species diversity.

The effects of oil spills are complex, whether from tankers, SPM's, platforms, or terminals. Some of the major components of fish and wildlife species and habitats that are affected [32] follow:

1. Endangered Birds - The known and suspected coastal habitats of the American Peregrine Falcon, Southern Bald Eagle, and Osprey, and other birds identified as sensitive in any seasons.

2. Migratory Waterbirds - Areas along the shore identified as having significant concentrations of migratory birds during the winter, spring, and fall seasons.

3. Shellfisheries - Areas along the shore identified as beds for surf clams, bay scallops, northern hard clam, oyster and others. Both commercial and sports harvesting areas for these species in any seasons.

4. Coastal Finfish - A 25-mile strip of coastal waters along the entire length of shore identified as critical during the summer and fall seasons with respect to the egg and icthyoplanktonic stages of the scup, porgy, menhaden and other species.

5. Estuarine Finfish - Estuarine areas and sounds identified as important areas for weakfish, sea trout, whiting, striped bass and other fish during the spring, summer, and fall seasons.

6. Wetlands - All marsh areas identified as sensitive in any seasons.

7. Wildlife Refuges and Management Areas - All national wildlife refuges, wildlife management areas, wildlife areas, and natural areas identified as critical in any seasons.

8. Beaches with High-Intensity Use - National Recreation Areas including adjacent state and municipal beaches identified as areas of high intensity usage in any seasons.

9. Parks and Recreation Areas - The locations of all state parks and national recreation areas recorded as important in any seasons.

10. Offshore Dumpsites - The locations of offshore ocean dumpsites recorded for any seasons.

Regulatory Factors:

SPM: A single point mooring system requires numerous federal permits and certificates associated with the location of a facility in navigable waters; dredge and fill; and pipelines. State and local permits are also required for associated landfall facilities.

Typically an SPM will be associated with a "deep-water port" or transshipment facility located outside the three mile (or marine league) limit of state jurisdiction. These facilities are governed by comprehensive federal legislation adopted by Congress as the Deep Water Port Act of 1974.

The Department of Transportation is the lead agency in licensing these facilities, including associated SPM systems. The Coast Guard manages the program. The Act sets up an "adjacent state" identification procedure and states identified through the procedure have statutory rights to advise and comment on the licensing process.

Associated facilities located nearshore or inshore are subject to the multiple jurisdictions described under "pipelines," (Section 2.2.4). The Corps of Engineers, Materials Transportation Bureau* and EPA are the primary agencies for the management of federal interests in construction and operation of these facilities.

Tankers: The Coast Guard maintains a surveillance and enforcement system for tanker operations in U.S. waters. These are defined in considerable detail in the Code of Federal Regulations, Volume 33, Part 155, and Volume 46, Chapter 1. United States flag vessels and foreign flag vessels in U.S. domestic trade are included under these provisions if they exceed a threshhold of 150 tons.

Oil spills from tankers fall under the Comprehensive Oil Pollution Liability and Compensation Act of 1975 which establishes a basis for liability for owners and operators of tankers and sets specific maximum amounts for liability.

Development Strategy

SPM's offer advantages over conventional deepwater port facilities. SPM's minimize mooring forces, can be adapted to a wide range of water depths, different bottom conditions and other varying environmental considerations. The initial cost of construction and installation time is considerably less than deepwater harbors or long piers. The need for dredging and related spoil disposal activities are eliminated and SPM's

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* The FPC licenses interstate gas pipelines.

can be utilized in the distribution of refined products as well as crude transfers.

One desirable feature of SPM's is they diminish tanker traffic around port areas and confined harbors, where maneuverability may be constrained. However, SPM's have been designed to work with the largest tankers; smaller tankers still operate along the coast and in industrial ports. In some areas, such as along the west coast of the United States, this trend is expected to grow rapidly when oil from the North Slope is transported into ports in California.

Decisions about single point mooring systems are generally made within two realms--the first relating to the whole transportation strategy for offshore oil, and the second relating to national policy on importation of oil.

An SPM operates solely as an oil transfer unit, however, the complete system would involve a power unit for pumping, submarine pipeline, landfall and a network of onshore pipelines, oil storage terminals and at times, refineries. An SPM system as proposed by Seadock would employ a number of SPM's connected to a complex of platforms by buried pipes. Discharged cargo at an SPM would flow through a floating hose to a buried submarine pipeline to a platform complex. From the platform, booster pumps would move the crude to an onshore storage terminal. From the storage terminal, the crude oil would be distributed by pipelines to refineries.

SPM's connected to shore terminals, as currently proposed, are primarily designed to handle imported crude oil. The approvals for SPM's--which require extensive State and Federal reviews--are therefore influenced by national policy toward reduction of dependence on imported crude.

2.3 ONSHORE DEVELOPMENT PROJECTS

Planning onshore development calls for different industrial strategy than offshore. Offshore is a high stakes game where huge investment is required to back up each project proposal; it is private enterprise operating in classic style where investments, risks, and the potential for returns are all large. Onshore is different because it is a lengthy process of solving an elaborate series of administrative hurdles imposed by Federal, state, regional and local authorities with relatively small investments. Offshore investment involves only the oil companies and major contractors while onshore investment also involves many small, independent support companies, or vendors, who supply and service the oil companies. Onshore activity is confusing as it includes a large number of enterprises in a complex industrial structure, has great investment flexibility, and actions of member industries are often difficult to predict.

The onshore development projects presented in this section are:

- 2.3.1 Service Bases
- 2.3.2 Marine Repair and Maintenance
- 2.3.3 General Shore Support
- 2.3.4 Platform Fabrication Yards
- 2.3.5 Pipe-coating Yards
- 2.3.6 Oil Storage

2.3.1 Service Bases

The supply and support of offshore rigs and platforms is a vital element in the effort to produce oil and gas in the marine environment. Only a limited amount of the necessary supplies can be stockpiled alongside the rig or platform during all phases of operation. It is essential that the supply line from shore to the offshore drilling area be maintained in an orderly and timely manner; an ineffective supply system can be very costly as any downtime due to lack of supplies and equipment add unnecessarily to the overall drilling costs.

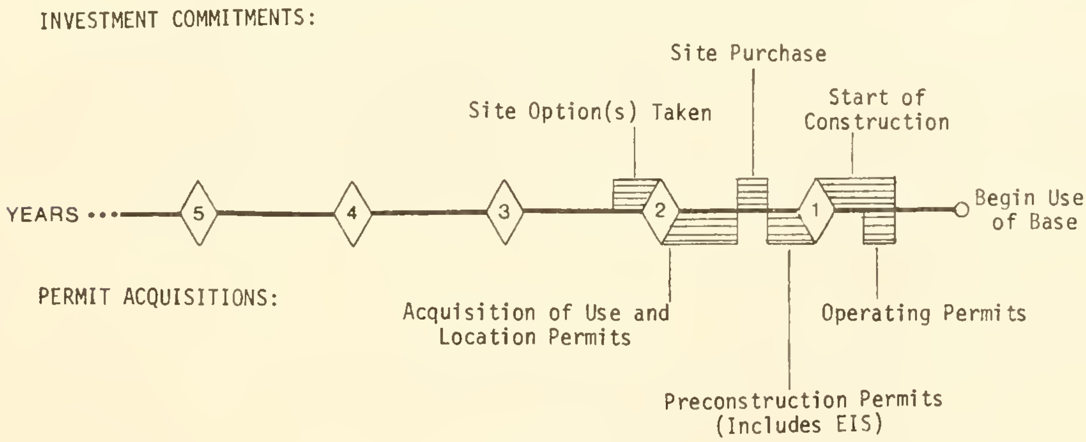
Service bases (or staging areas) are the logistical links between offshore and onshore activities. The main activity of a service base is the transfer of materials and crew members required to operate rigs and platforms between land and offshore operations. Service bases contain berths for supply boats and crew boats, dock space for loading and unloading, warehouses, open storage areas, office space, trucking and freighting facilities, and a machine shop. Optional facilities may include a mineral-processing area (for drilling-mud preparation), an offshore workover area (for reworking of producing wells), and possibly a helicopter landing area for personnel transport. Numerous additional facilities are required to support the central staging area as an effective and efficient base of operations. These operations include food/catering establishments, marine equipment distributions, and repair shops.

Service bases are sometimes set up by the oil companies for their own use, or they may be built and operated by companies which specialize in serving offshore operations and under contract to the oil companies (Figure 27). Support bases have traditionally been established by drilling-mud supply companies (known as "mud companies"). More recently, specialized companies have evolved whose main function is the establishment of service bases, such as the Aberdeen Service Company Ltd., in Scotland. Some major oil companies, since they either own or have rigs on extended contract, prefer to carry out their own operations onshore. Other oil companies find that a base run on a large scale by another company provides an attractive alternative due to the flexibility it allows.

Description

Service-base components will vary depending on the size and rate of production of offshore resources. Requirements are also a function of available community and industrial infrastructures. In frontier areas, service bases may be largely self-contained in rural environments such as Alaska; or may be a new component to a developed waterfront port in east coast locations.

Figure 27. Service base* - project implementation schedule.



* Note that this schedule applies to permanent service bases only.

The comprehensive service base contains the following minimal components:

1. Sheltered deepwater harbor
2. Adjacent flat land for open storage
3. Wharf or pier space
4. Warehousing
5. Tanks for fuel storage
6. Silos for drilling mud and cement
7. Administrative offices
8. Heliport
9. Supply vessel fleet (see Section 2.3.2)
10. Cranes and loading equipment
11. Space for company dispatchers and communications equipment

Optional components include:

1. Open storage for coated submarine pipe
2. Open storage for anchors and chains
3. Machine shops, repair, maintenance and welding facilities

(A site plan of a new permanent supply base in Lerwick, the Shetland Islands, is reproduced in Figure 28).

An onshore support base will also need an area set aside for a mineral-processing plant, and space for vessel repair and maintenance. The former is required to prepare drilling mud, an essential component of all drilling operations. The basic drilling-mud composition tailored to meet specific down-hole requirements is prepared at the plant, although it may be slightly altered by the drilling-mud engineer on site.

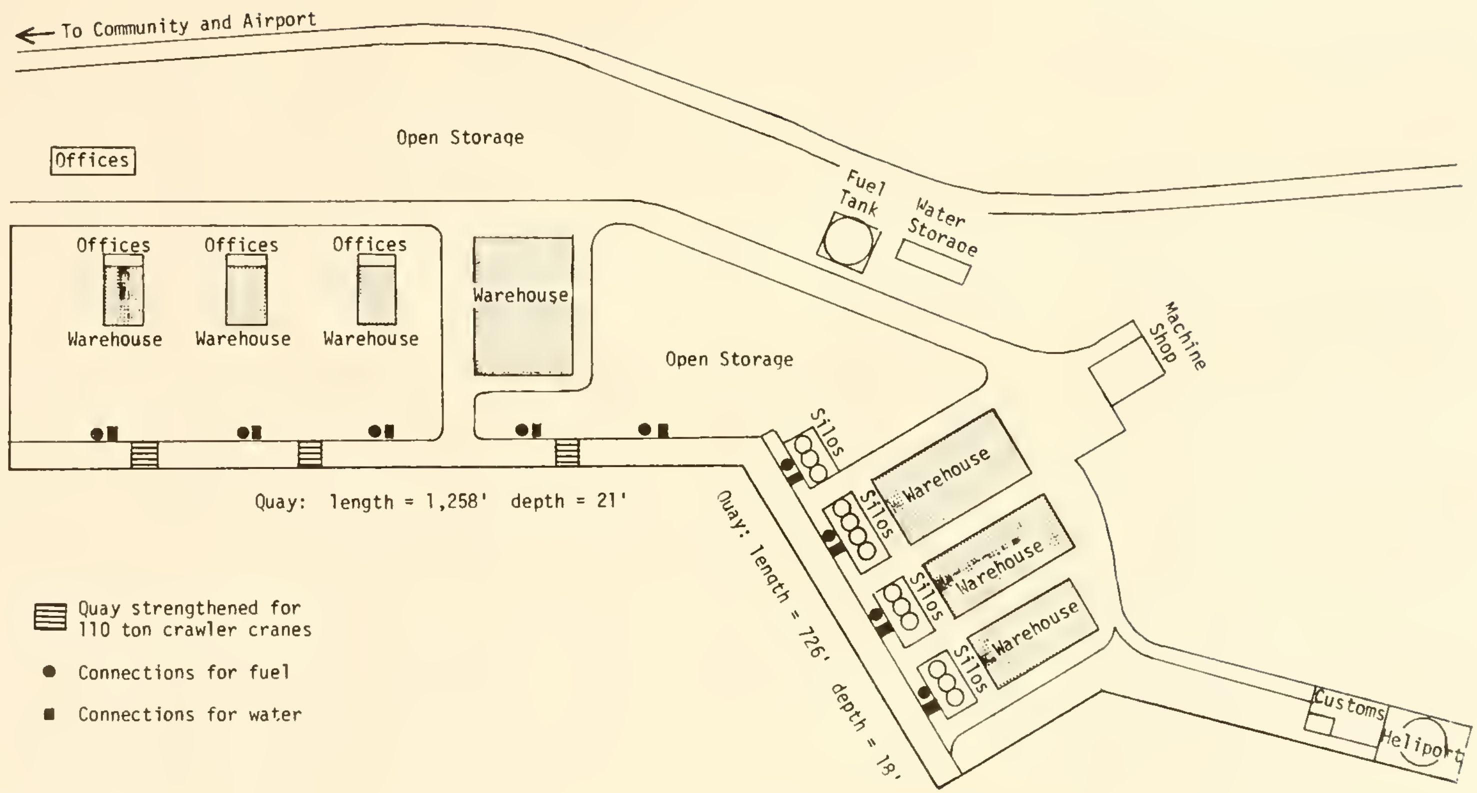
Back-up services might include [34]:

1. Specialized drilling services
2. Engineering services (repairs to equipment and small fabrication)
3. Inspection services
4. Diving (underwater inspection and maintenance)
5. Catering services
6. Air services
7. Freight handling, customs documentation, etc.
8. Agents of supply boats, tugs, etc.
9. Dredging and harbor works
10. Communications
11. Secretarial services
12. Emergency medical services

An important distinction is to be made between <u>temporary</u> and <u>permanent</u> service bases. During exploration and exploratory drilling, only <u>temporary</u> facilities are developed. Temporary service bases are comparatively small operations, and the limited acreage (5 to 10 acres) which they use is usually leased on a short-term basis. Public port facilities already in operation are often used during the exploratory phase.

After a commercial find has been located, land for a <u>permanent</u> base (usually 50 to 100 acres) will be purchased or leased on a long-term basis (more than one year). (Figure 27 is for <u>permanent</u> service bases.) During field development, service bases supply essentially the same types of goods and services required during exploratory drilling. However, the scale and intensity of support services increases significantly for two reasons. First, as many as 60 wells can be drilled from

Figure 28. Site plan for a comprehensive supply and service base: Lerwick, Shetland Islands (Source: Reference 33).



each platform which increases the number of personnel and supplies needed. Second, success in a portion of a basin stimulates increased exploratory activity by other lease-holding companies. A permanent base contains more extensive and sophisticated facilities than a temporary base in order to sustain the increased volume of supply-vessel traffic which results from the escalated level of offshore activity.

Site Requirements

A site for a shore base to support offshore oil or gas activity must be selected with care, so as to minimize the risk of delay and to avoid increased costs to offshore operations. Nine site requirements are commonly investigated to determine a location for a permanent service base [34]:

1. Proximity to offshore oil or gas activity
2. Existence of previous bases
3. A sheltered harbor of suitable size and draft with available capacity
4. An adequate waterfront site with contiguous back-up lands
5. Suitable airport/heliport
6. Adequate roads
7. Proximity to an established community
8. Temporary base site
9. Other factors

1. Proximity to offshore activity: This requirement reduces the running time required for boats to ferry supplies from the service base to the offshore installations. Proximity is critical because good weather conditions may last for only short periods of time and because the operation of supply boats is the greatest operating expense of a supply base.

2. Existence of previous bases: When a company has a permanent base in the general area of a new lease, it will either operate out of this base (rather than build a new one) or set up a satellite base for the small, day-to-day logistical activities and use the permanent base for transporting the bigger supplies and equipment.

The decisions to establish a temporary base that is nearer to the locus of offshore activity than an existing permanent base affects space requirements for storing and loading supplies, as well as the volume of boat and helicopter traffic.

New facilities to service a rig operating within 100 miles of a permanent service base are unlikely. If a rig is between 100 and 150 miles away from a permanent service base, a temporary base is likely to

be set up at least for changing crews, either by boat or helicopter, and for supplying small items not peculiar to the drilling industry; larger supplies, such as casing, mud, and cement will be supplied from the permanent base. Beyond 150 miles the creation of an independent base becomes increasingly probable [26].

3. Sheltered harbor: The availability of adequate sheltered harbors in the general area of offshore leases or proposed areas of activity is a major factor in locating service bases. The harbor must permit the loading and sheltering of supply vessels whose size, draft, and capacity are three important considerations. At a minimum, the harbor should have the physical dimensions to allow the maneuvering, anchoring, and berthing of a large number of offshore supply boats, ocean-going barges, and other vessels supplying the base.

Since many supply vessels may sit idle between trips or may be loaded and have to wait for the weather to improve before going to sea, the capacity of a harbor is also significant. Ideally, all vessels should be able to moor at shoreside. However, if sufficient dock spaces are not available for this, capacity must be available to moor the supply vessels two or three abreast at shoreside, or space must be available to safely anchor them in the harbor (20 to 30 feet depth).

4. Waterfront site: Service-base operation efficiency is measured in terms of turnaround time, the time required by a vessel to dock, to load all of the supplies requested, and to start back to the offshore operations. It is, therefore, desirable that oil service bases be set apart from the plants and boats of the fishing industry and other users of the waterways to avoid delays caused by congestion with other vessels and conflicting use of waterfront facilities.

The location within the harbor also requires large quantities of flat land, or back-up land, adjacent to the dock locations on the waterfront. At dockside there are minimum requirements for staging areas, silos, warehouses, storage tanks, and open storage. However, the large quantities of pipe goods handled and stored also require flat areas. If flat land is unavailable, it is, of course, possible to cut and fill during the construction of the service base facility.

5. Airport-heliport: In areas where road and rail connections are undeveloped, it is essential that a service base be connected by road to an airport, preferably one with scheduled main-line service and wiht facilities to handle heavy cargo services and helicopter operations for offshore areas. The principal function of an airport serving offshore oil operations is the transport of crews to and from the offshore facilities. However, the marine service base also requires the services of the airport and/or heliport: (1) to permit the rotation of the supply-boat crews, (2) to transport emergency supplies and service personnel

via helicopter to offshore locations, (3) to receive emergency supplies for shipment by supply boats to offshore facilities, (4) to transport sick or injured workers to major medical facilities, and (5) to enable administrative and technical personnel from both industry and government to have ready access to the service base [26].

6. Roads: Adequate roads between the airport and the service base are essential, since there will undoubtedly be occasions when large quantities of tubular goods and other heavy materials will be transported between the airport and the service base. Similar requirements will be demanded within the service base where heavy loads will be constantly shuttled to and from storage areas. Aside from these basic road requirements, an adequate road between the service base and the adjacent community will also be needed.

7. Proximity to an established community: A community can provide the service base with elements essential to its operation that would otherwise have to be brought in or constructed, including labor force, utilities, and local supplies. These factors are discussed in the section on Community Effects.

8. Temporary base site: During the exploration phase, the number of temporary bases and their distribution among available ports in a region will depend on several factors: the number and distribution of lease holdings, the distance from the port to the leased tracts, and the location of existing bases operated by lease-holding companies.

The location of bases established during the exploration phase may prove convenient for the development phase as well. However, if the oil field is located a considerable distance from the temporary base used during exploration, the permanent base may be set up in a more convenient location. The incentive to make this move increases if the supply haul is long, if the field is large, or if there are a number of fields being developed. The decision to move may be less complicated for those companies which have not set up semi-permanent facilities during exploration. Companies with short-term contracts for mobile rigs, berth space, and back-up land are more likely to move their bases as the offshore exploration proves successful.

Temporary bases are often set up under less than ideal conditions, since the activity level in the preliminary phase of offshore exploration is relatively low and the future development potential uncertain. Hence, they may have inherent limitations, such as insufficient acreage for expansion, or insufficient linear dock space to support projected future levels of vessel activity brought about by accelerated OCS development. If such is the case, the company may have to look elsewhere for a site for a permanent base even if the original base site is sufficient in all other respects. Ability to expand the initial site is therefore

an important concern in locating the temporary base. If a commercial find is discovered by the same company which used the temporary base, the permanent base will probably be set up in the same port.

It should be noted that an early commitment to a service base does not necessarily commit the area to other facilities demanded during subsequent OCS development stages, such as terminals or processing plants. Although industrial incentives lean toward locating facilities together, there is little evidence to suggest that industry now situates facilities to support early OCS development stages (such as service bases) with later joint facilities in mind.

9. Other factors: Experience in the Scottish sector of the North Sea has indicated that, despite disadvantages in location, some communities have attracted service base activity through a willingness to satisfy industry demands in a timely manner [34]. However, in other instances, despite the presence of efficient comprehensive service base facilities open to all, on contract or otherwise, independent control of service base operations may be highly valued by a particular operating company.

Construction/Installation

Construction of a service base involves shorefront preparation. A service base will locate where shorefront port facilities meeting water depth requirements are already available. This minimizes costly start-up time spent in lengthy permit procedures for dredge and fill, zoning, and other procedural requirements. Under certain conditions, dredging and filling may be required either as the base develops or for maintenance purposes. The base will evolve in size and services concurrently with offshore operation growth and field development.

Construction of the base is a relatively rapid process; however, the base will probably not be completed during a single construction phase. Components of the service base will be constructed in response to offshore service demands which include the size and age of the field, new discoveries, and other factors. The construction process for these facilities should be of limited environmental concern after the site has been prepared in accordance with environmental safeguards. As the service base responds to rapidly evolving offshore needs, the availability of a site ready for construction is important to the supply-base contractors.

Operations

The central staging area is the heart of the exploration, development and production activities for offshore petroleum. Figure 29 shows the movement of persons, equipment, and materials through the central staging area to and from the mineral-processing area, workover area; offshore

operations, and onshore support functions. An example of the types and quantities of goods required to support each exploratory well are listed below [34]:

	10,000' Well	14,000' Well
30" Casing	18	18
20" Casing	28	28
13 3/8" Casing	82	82
9 5/8" Casing	---	168
Bentonite	467	700
Cement	275	300
Barite	233	350
Miscellaneous consumables	10	10
Fuel (including supply vessel fuel)	1,580	2,400
Drill Water	2,500	3,750
TOTAL	5,193 tons	7,811 tons

Although the level of activity in a few service industries will peak during the development phase and taper off during the production phase, there will most likely be an increasing market for maintenance services at the platforms and other facilities. While the relative size and activity of component industries oscillates during the life of the field, all service bases have common components.

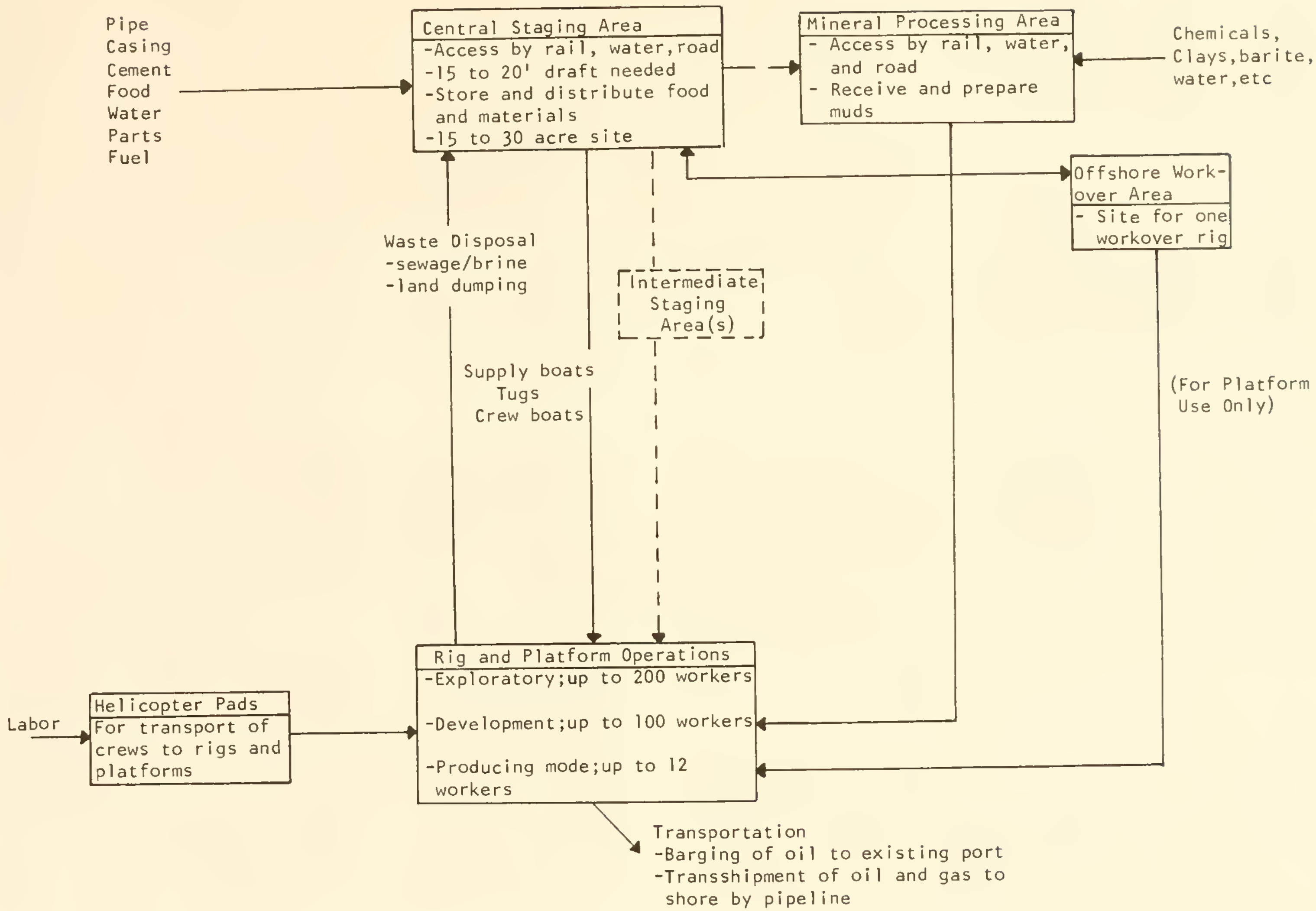
Community Effects

A service base is characterized by the following attributes of interest to shoreline communities: major source of employment for both construction and operation, potential tax base, medium-size parcel of land along the waterfront in a developed harbor and access to all transportation systems.

Employment: Assuming new facilities are required for a permanent support base, one study suggested an average of 20 and a maximum of 90 employees would be required during a one-year construction period. This level of activity would be a measurable generator of income in a small community [28]. A temporary base, by contrast, will use or modify existing structures and facilities to minimize investment, thus providing minimal construction employment.

During the exploration phase a temporary service base involving minimal investments would be located in a frontier area. The total

Figure 29. Staging area requirements of offshore activities.



number of jobs in a temporary base in Florida was 32 jobs, 12 of which were filled by local residents [26].

Employment at a service base varies with the stage of field development as shown below. All figures are per platform [26].

	Personnel Required During Offshore Field Phases		
Facility	Exploratory Drilling	Production Drilling	Production
Supply boat	30-36	30-36	16
Crew boat	6	6	---
Helicopter	3	3	3
Wharf & warehouse	4-6	9	3
Total	42-54	48-54	22
Local personnel	20-22	---	18-22
Total salary (17,000 avg.)	$734,000	$816,000	$374,000

Induced Effects: Local employment and temporary residents will bring additional funds into the community, stimulating commercial activity. Most jobs require semi-skilled help which should be available in any developed port. This income will have a multiplier effect on the economy of the community. In addition, physical facilities will add to the tax base. If the port already has commercial services, service demands based on anticipated OCS development should not burden existing capabilities.

The average wage rate is likely to be higher than that for traditional waterfront employment. Thus, workers may be attracted away from other commercial enterprises, such as fishing. The number of local people employed in the service base is almost constant, the variable being non-local labor. Therefore, the individuals diverted from existing employment sources would not return to the traditional activities for the duration of the field's productivity, a span of at least 20 years.

Effects on Living Resources

A service base has the following characteristics of particular concern to fish and wildlife: (1) piers and bulkheads; (2) channels and

turning basins; and (3) filling of wetlands, which must be considered during the location, design, construction and operation of the facility.

Location: The ecological problems related to service bases are primarily a result of the necessity to situate the facility on the waterfront. With crew boats and supply boats constituting the main link between offshore needs and onshore supply, sponsors desire a sheltered channel or harbor allowing efficient loading and unloading. Locations at the mouth of bays and estuaries will aid in the flushing and dispersion of silts stirred by boat propellers and petroleum discharges from engines. Channels and harbors that require little initial or maintenance dredging should be considered as first choices for the locations of service bases.

Design: All possible attempts should be made to locate service bases on existing waterfront property to avoid the loss of fish and wildlife habitat through filling of wetlands. The need for navigable channels and turning basins will cause dredging problems of turbidity and sedimentation, which may lead to the smothering of clams, corals, and other sessile organisms. Channels should be designed to limit the amount of initial or maintenance dredging, i.e., the channel route usually should be the shortest distance to the service base. However, the type of substrate must also be considered. Loose, unconsolidated material requires more frequent maintenance dredging.

Construction: With the construction of a bulkhead to service boats, shores are often dredged to create the berth area and to obtain fill to place behind the bulkhead. Although inexpensive and quick, this method alters the natural configuration of the shoreline and robs areas downshore of needed sand by interrupting littoral drift. Additionally, solid-fill structures tend to intercept, divert, and disperse water currents in directions where previously they had not gone or cause them to become diffused through mixing with other currents. This diversion may decrease available food supplies and change water parameters, such as salinity, oxygen, etc., leading to a significantly altered fish and wildlife habitat. If wetlands are filled, there will be a loss of breeding/feeding grounds and generally productive areas for fish and wildlife. Construction of open pile piers and floats will greatly reduce the above effects.

Operation: Regarding service-boat traffic between offshore rigs and the service base, the sponsor will find it necessary to ensure that accidental and illicit discharges be kept to a minimum. All boats should be rigidly inspected to prevent any unnecessary oil and grease from entering the water. Also, transfer of drilling mud and other compounds from the marine terminal to the boat should be executed according to pre-established safety procedures to reduce accidents to workmen and to the environment.

Regulatory Factors

Service bases are likely to be located in existing harbor facilities where state and local certifications or permits may not be required or, if required,are straightforward. Creation of a new harbor facility, however, will entail the process of state and local approvals. Because service bases nearly always require channel modification or maintenance, Federal dredge and fill permits are an important consideration in site selection.

Federal Role: The Corps of Engineers issues dredge and fill permits under the authority of Section 10 of the Rivers and Harbors Act of 1899, Section 404 of the Water Pollution Control Act Amendments of 1972, and regulations that they issued July 25, 1975, in Volume 40 of the Federal Register, pages 31320 et seq. The Fish and Wildlife Service must be consulted before the permit is issued. In addition to commenting on technical questions related to wildlife and habitat conservation, FWS recommends mitigation measures. The District Engineer issues the permit unless timely objections are filed by interested parties, including the FWS. If substantial objections are filed the decision is referred to the Division Engineer. If the FWS maintains its objection, the decision to issue the permit must be made in Washington by the Secretary of the Army after consultation with the Fish and Wildlife Service through the Secretary of the Interior. Fish and Wildlife Procedures are set forth in the Navigable Waters Handbook of the Service.

Development Strategy

The oil or drilling company's (and suppliers') strategy for selecting a location for a support base centers on finding an adequate site which can be rapidly developed when needed to support offshore operations. The background investigations to determine a specific strategy in a frontier area are initiated by a port survey. After the survey is completed and analyzed, the variables considered for selecting the initial, temporary site might include available facilities, community attitudes, costs,long-term development potential, and the site requirements discussed earlier in this section.

If any developed ports lie within approximately 200 miles of an offshore field, it is unlikely that an undeveloped harbor would be considered. Delays caused by required waterfront and harbor site preparation in an undeveloped area will be bypassed. Delaying factors to be avoided may include procedural requirements, site preparation requirements, or land availability. The two pressures causing a company to select an undeveloped area over developed alternatives are: (1) the undeveloped harbor is significantly closer to the field, (2) or the political posture of the community at the developed harbor (as expressed through zoning ordinances, land use plans, and policies, etc.) is negative to the proposed development.

In a potential frontier region that contains ample ports, e.g., New England, each (major) drilling company will identify two or three potential ports which can meet the needs for setting up a temporary base of operations. There is uncertainty associated with the offshore leasing process and companies are not sure which tracts (if any) they will own an interest in until after the sale. Therefore, neither options nor acquisitions are likely until after the lease sale.

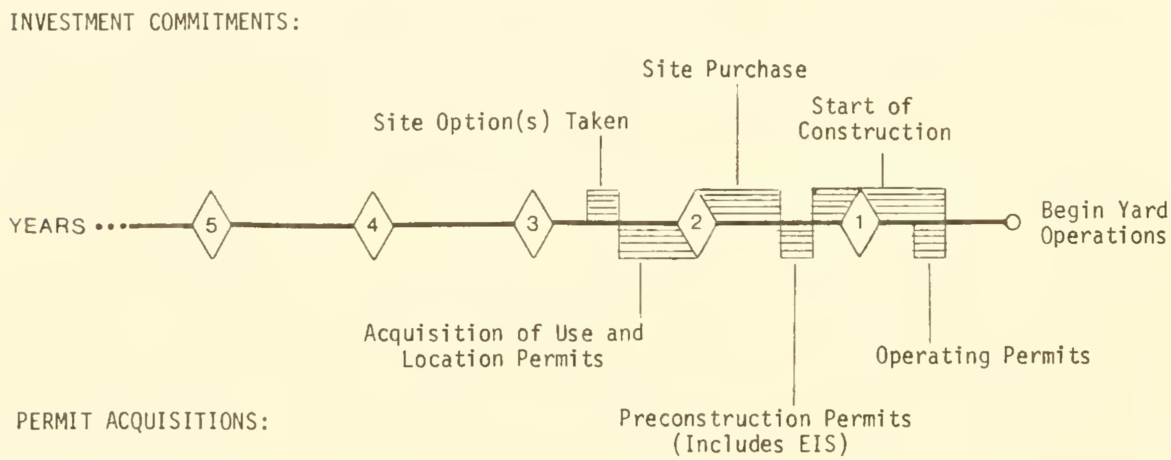
Recognizing the uncertainty faced by the oil companies, a mud company or service company will sometimes establish a base in a port that is convenient to the lease area and that possesses the necessary site requirements; then the mud company or service company may attempt to make an arrangement with one or more oil companies by offering free dock space in exchange for the contract for mud and/or drilling fluids. This strategy may result in several oil companies operating out of a single base. Since the service industry is so highly competitive, three or four such bases may possibly be set up in different ports.

After a temporary base is established,the company will probably continue to develop the site into a permanent base, if offshore discoveries merit increases in onshore development. The desire to stay in the same location reflects industrial inertia fostered by a familiarity with the capabilities and limitations of the temporary site. If another site were selected, additional unproductive efforts such as altering the supply system associated with transportation, hiring a new labor force, and closing down the temporary base would increase present costs and would offer returns only in the future. The only two possible reasons for relocating the supply base are: (1) need for additional land space or waterfront for significantly increased activity, or (2) selection of a site closer to the offshore leases. The latter cause is a real possibility under the frontier lease system, as large areas are leased simultaneously and the possibility of discovery exists in each leased tract. Companies, however, are aware which tracts are considered most likely and, therefore, attempt to minimize the necessity for relocating their supply base by selecting a site close to the "best" tracts.

2.3.2 Marine Repair and Maintenance

The petroleum industry uses many types of vessels in offshore activities. These vessels may be owned by the oil companies, by supporting companies, or by independent companies whose business is making necessary support vessels available on a charge basis (see Figure 30). A partial list of these vessels is given in Table 12. Examples of typical support vessels built by a major supplier are profiled in Figure 31.

Figure 30. Marine repair and maintenance - project implementation schedule.



Shipyards, or marine repair and maintenance facilities, are used to keep these vessels in good operating condition. The industry is not a single firm or specific facility, but rather a range of firms that are used to repair and maintain the wide variety of OCS-related vessels and equipment. These firms already exist in many ports to maintain all types of commercial marine vessels, and the development of OCS-related activities will be an additional source of work and income to these firms. Although OCS activity may stimulate additional firms, there is a greater likelihood for existing firms to expand.

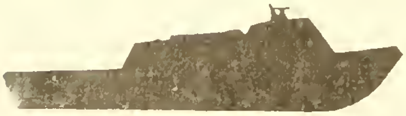
Table 12. Some Vessels Used in Offshore Petroleum Recovery Activities

Type of Vessel	Description
Crew	For personnel transport; high speed boats.
Utility/supply	General maintenance and movement of light-weight equipment and cargo.
Supply	For transport of bulk cargo.
Utility	Maintenance and general work.
Tug	Light to heavy towing.
Tug-supply	Moderate towing and transport of portable equipment and cargo.
Crew/utility	For personnel transfer and general work.
Crew/supply	For transfer of personnel and equipment.

Existing boatyards in the adjacent onshore region may experience increased activity for repair and maintenance of the fleet of vessels associated with offshore drilling. An increased level of business can also be expected for welding and machine shops, caterers, and transport companies.

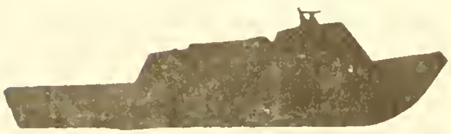
Most of the United States onshore support operations are located on or near the Gulf of Mexico because the OCS business started there. However, this location is not a constraint in supplying equipment for OCS utilization on a worldwide basis. For example, there are ten shipyards in the United States which have the capability to construct and service offshore mobile exploratory rigs. Five shipyards are located in Texas, at Beaumont, Brownsville, Orange, Galveston, and Ingleside; one each in New Orleans, Mobile, and Vicksburg; and two on the Pacific Coast at Takoma and Oakland. The scale of the rig-building industry is indicated by the fact that in mid-1975, the value of rigs under construction exceeded $1.0 billion. Shipyards for the construction and maintenance of support craft, including survey boats, are likewise clustered around the Gulf Coast.

Figure 31. Characteristics of typical support vessels (Source: Reference 35).



65 FOOT CLASS
M/V Aunes-Crewboat
Specifications:
Horsepower: 850
Dimensions: 65' x 17' x 10'
Speed 26 MPH
Fuel Capacity 950 Gals
Passengers 34

110 FOOT CLASS
M/V Bay Seahorse-Production/Utility Vessel
Specifications:
Horsepower 1936
Dimensions 110' x 25' x 11'
Speed 16 MPH
Fuel Capacity 13,000 Gals.
Passengers 34



100 FOOT CLASS
M/V Canadian Seahorse-Crewboat
Specifications.
Horsepower: 2050
Dimensions: 90' x 21' x 7.5'
Speed 25 MPH
Fuel Capacity 2,500 Gals.
Passengers 44

8000 HORSEPOWER CLASS
M/V Atlantic Seahorse-Tug/Supply Vessel
Specifications.
Horsepower. 7568
Dimensions: 210' x 40' x 17.5'
Speed 16 MPH
Fuel Capacity 150,000 Gals
Below Deck Mud Capacity 4,000 Cu. Ft.
Chain Lockers 8000' of 2-3/4" Chain
Towing/Anchor Handling Winch 350,000 Lb Single Line Pull
Bow Thruster 500 Horsepower Producing 10,000 Lbs Thrust

165 FOOT CLASS
M/V Bengal Seahorse-Supply Vessel
Specifications:
Horsepower: 2550
Dimensions: 166' X 38' X 13'
Speed: 14 MPH
Fuel Capacity. 45,000 Gals.
Below Deck Mud Capacity 2,000 Cu. Ft.

It is difficult to predict the ultimate extent of expansion of various shipyards and fabricating yards associated with the frontier OCS areas. There are a variety of factors that could prompt a builder to expand from the Gulf Coast to the East and West Coasts:

1. degree of success of oil and gas discovery;

2. backlog of orders in his current facilities;

3. company forecast of new business a facility could generate and its profitability; and

4. zoning regulations and environmental restrictions that may preclude timely development of a new facility.

For the next few years a wholesale shift of construction facilities to the OCS frontier area is not anticipated. However, if these new zones are productive, many companies will consider moving construction facilities to the areas during the mid-1980's.

Description

The diversity and quantity of requirements for marine repair and maintenance facilities increase as the number of vessels increases. Two or three vessels are associated with pre-lease drilling; more substantial needs appear in the exploratory phase, and even more extensive needs are indicated by a mature field with production workover phases.

A repair and maintenance yard (or facilities) is located on the waterfront in a developed harbor. The equipment and layout of the yard reflect the needs of the port and can vary considerably. A large facility servicing a major port might include pipe, plate, and welding shops, storage buildings, dockside ship service facilities, and a dry dock. These facilities would be situated within the site to allow docked vessels to be easily serviced.

Dry docks are needed for repairs on the hull, shafts, and propellers. The majority of boat repairs can be made while the vessel is in the water. If possible, boats are "hauled out" only in cases of necessary bottom work or for periodic Coast Guard certification and licensing inspections.

Marine repair and maintenance facilities are located in developed harbors in response to demand associated with initial commercial harbor users. Existing facilities will be used initially unless a major field is found in a frontier area where no developed ports are available within an appropriate distance. As the field is explored and developed

the gradual buildup in demand for this service by OCS-related companies means an increase in business for enterprises already supporting fish or commercial shipping concerns. These repair and maintenance businesses will expand staff, inventories, and work space to accommodate the new vessels.

The initial fleet of boats serving a frontier area may well be contracted from an established company in the Gulf Coast area. A boat-chartering company may decide to locate a branch office in a harbor near the frontier area if the demand for vessels increases. A simple site might include berths, crew quarters, and office space to operate the chartering service. Repair and maintenance services would be sought from nearby established facilities. Or the company, anticipating continued increases in offshore development, may establish a small repair and maintenance area to handle most work on its own boats.

Alternatively, established shipyards may develop specialized repair yards for petroleum-industry work boats, probably adjacent to their larger operations. Along the Gulf Coast and in the North Sea skilled mechanics from existing shipyards or related heavy industry have opened small independent repair and maintenance service operations, catering to specialized oil and gas industry work [26].

Construction/Installation

Increased OCS activity will not be expressed in major construction at new sites, but rather in less significant construction to expand existing wharf and support areas. If a large number of additional vessels require service, additional entrepreneurs may be attracted. However, they would not invest the capital necessary to build a dry dock or other major facilities; rather they would obtain or purchase some dock space and would compete by performing specialized aspects of maintenance. The only exception to this process would be investment by a charter service for oil-industry vessels. If a large field with diversified activities and needs were predicted, such a charter service might construct a new major repair and maintenance facility primarily to service its own vessels.

Operations

Basically, two types of maintenance repairs are peformed: mechanical and electronic. This work is done either at dockside or with some degree of "haul out" ranging from the use of a derrick and flotation barge to the use of a dry dock. Mechanical repairs are made on the major and auxiliary drive trains, diesel engines (Caterpillar, Alco), reduction gears (Caterpillar, Lufkin), shafts, and wheels. Mechanical repairs also include repairs to the vessel superstructure, such as

welding, scraping, painting and associated work on the boat body and compartments, and repairs of auxiliary mechanisms such as generators, pumps, winches, anchorage gear, etc. Electronic repairs are made on instruments, such as radios, radar, LORAN, and fathometers [26]. Large vessels, such as pipe-laying barges, drill ships, semi-submersibles, and other large OCS-related carriers will be serviced of necessity in major shipyards. These large shipyard facilities are involved with construction and conversion of vessels, as well as with repair and maintenance. Here the largest boats can find dry dock facilities and most other services normally required by such vessels. The OCS-related vessels will merely be a new client for existing businesses.

The most likely sources of service for these vessels is at those harbors that customarily service larger commercial fishing vessels. The facilities used by commercial fishermen normally have sufficient "haul out" and repair capability [26].

Community Effects

Marine repair and maintenance facilities in developed harbors may expand if warranted by increased demand for services from OCS-related vessels. Expansion may include additional waterfront, but it is more likely to be reflected in new equipment, increased employment, and expanded service facilities such as machine shops.

Employment: Employment in existing yards will increase if the firms are to provide the additional service. Labor requirements range from skilled and specialized capabilities for repairing electronic gear to semi-skilled and unskilled jobs of scraping hulls and other heavy labor. Some skilled positions may attract new workers from other areas, especially if those skills are not readily available in the regional labor pool.

Induced Effects: Expansion should require only a minor increase in the demand for services. The greatest effects would involve sewage and solid waste disposal. However, these services may already be provided within the repair yard. Any increased development because of increased employment should be minimal. Expansion of an existing enterprise under these circumstances is desirable for a community because it costs little in additional services; but it increases the tax base, employs people in categories of potential chronic unemployment, and helps insure the survival of the businesses for a few years.

Effects on Living Resources

A marine repair and maintenance facility has the following characteristics of particular concern to fish and wildlife: (1) piers and bulkheads; (2) channels and turning basins; (3) dry docks; and (4) filling

of wetlands. These must be considered during the location, design, construction and operation of the facility.

Location: With ships, boats, and drilling rigs needing maintenance on a regular schedule and occasionally needing emergency repairs, a facility is usually located in a sheltered channel or harbor. This allows easy access for vessels and gives the protection from the open ocean necessary during repairs. Location at the mouths of bays and estuaries would aid the flusing and dispersion of silts stirred by boat and mobile-rig propellers and of petroleum discharges from engines. Channels and harbors that require little initial and maintenance dredging should be considered as the best choices for the location of facilities.

Design: Repair and maintenance facilities should be placed on existing waterfront property to reduce adverse effects on fish and wildlife. This would avoid the loss of fish and wildlife habitat by the filling of wetlands.

The need for dredging navigable channels and a turning basis will cause problems of turbidity and sedimentation, which may lead to the smothering of clams, corals, and other organisms. Oxygen depletion is also associated with dredging. Channels should be designed to limit the amount of initial and maintenance dredging. The channel route should be the shortest distance to the facility for dredging with minimum disruption of fish and wildlife habitat. Also to be considered is the type of bottom material, with loose, unconsolidated material requiring maintenance dredging more often.

Floating dry docks should be utilized where feasible instead of excavated dry docks. Floating dry docks reduce the need for excavating wetlands; such excavation leads to reduced aquatic productivity and loss of breeding/rearing areas.

Construction: Open pile piers and floats should be built instead of sheet steel bulkheads. In the construction of steel bulkheads for the repair of boats, shores are often dredged to create a berth and to obtain fill to place behind the bulkhead. This alters the natural configuration of the shoreline and robs areas down the shore of needed sand by interrupting littoral drift. In addition, solid-fill structures tend to intercept, divert, and disperse water currents. This diversion decreases available food supply and changes water parameters, such as salinity, oxygen, etc., leading to a significantly altered fish and wildlife habitat.

Operation: When repairs are being conducted on ships and rigs in the facility, all vessels should be inspected to prevent any unnecessary oil and grease losses. Vacuum trucks and other skimming devices should

be employed to remove any collected oil. Any damaged vessels that transport petroleum products should have oil booms placed around them to contain discharges into the water during repairs.

Regulatory Factors

Marine repair and maintenance facilities are likely to be located in existing harbor facilities, where state and local certifications or permits may not be required, or if required are straightforward. Creation of a new harbor facility, however, will entail the process of state and local appovals briefly outlined in Section 2.1.3. Because these harbor facilities usually require channel modification or maintenance, Federal dredge and fill permits are an important consideration in site selection.

Federal Role: The Corps of Engineers issues dredge and fill permits under the authority of Section 10 of the Rivers and Harbors Act of 1899, Section 404 of the Water Pollution Control Act Amendments of 1972, and regulations that they issued July 25, 1975, in Volume 40 of the Federal Register, pages 31320 et seq. The Fish and Wildlife Service must be consulted before the permit is issued. In addition to commenting on technical questons related to wildlife and habitat conservation, FWS recommends mitigation measures. The District Engineer issues the permit unless the Regional Director of the FWS objects. An FWS objection requires the permit decision to be made in Washington after consultation between the Corps and the Department of the Interior.

Other Federal agencies may also comment on these applications. Their objections result in review by the Division Engineer of the application who either directs the District Engineer to issue the permit or recommends denial. EPA theoretically has a veto in the process, but the regulations under which a veto would be exercised have yet to be promulgated.

Development Strategy

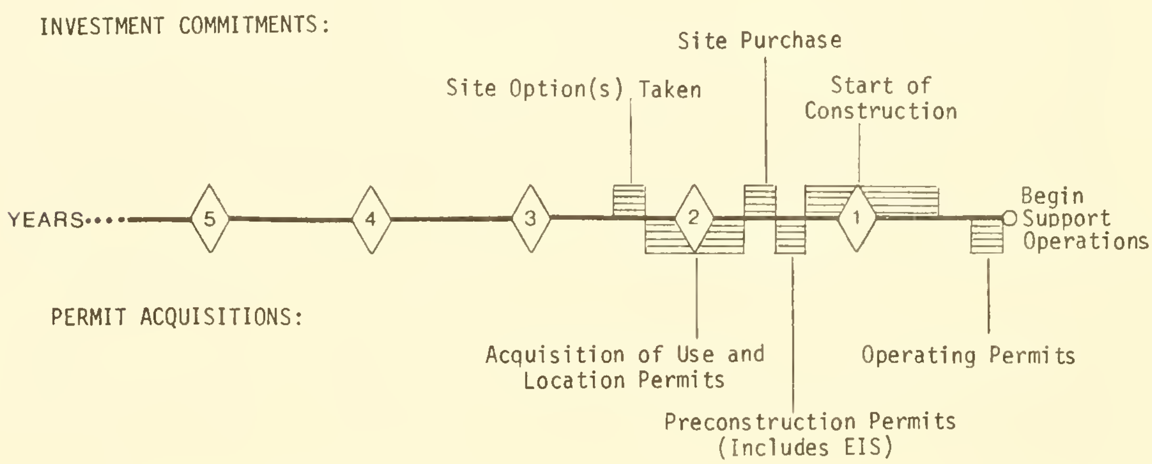
The strategy of marine repair and maintenance yards involves augmenting existing facilities to provide prompt service for OCS-related vessels. The development of this capability is a variable mixture of expanding existing businesses and initiating new businesses, especially for some of the specialized vessel needs. In harbors where extensive capability already exists, such as Long Beach and San Diego on the west coast, Mobile on the Gulf, and Gloucester in the northeast, little additional development should be anticipated. The less the existing port capability, given a constant resource size, the greater would be the required repair and maintenance development.

In addition, the repair and maintenance industry will expand in direct response to the intensity of offshore activity.

2.3.3 General Shore Support

Independent companies are contracted by the offshore petroleum industry to provide a wide variety of specialized services. These companies are called general shore support or ancillary services. These companies are usually small and specialized. They typically require limited space and equipment, and are a potential for local employment (see Figure 32). One study lists more than 120 companies in this category [19].

Figure 32. General shore support - project implementation schedule.



General shore support includes all specialized OCS-support companies not included in Section 2.3.1 (Service Bases) and Section 2.3.2 (Marine Repair and Maintenance). The combination of enterprises described in these three sections (2.3.1, 2.3.2, and 2.3.3) would include all the onshore industries which support and service OCS facilities on a day-to-day basis. These firms may also serve other onshore facilities such as platform fabrication yards, natural gas processing plants, and refineries. For some firms, such as a catering service, supporting offshore activities may be one of many contracts; other businesses, such as mud suppliers, serve only the petroleum industry.

Description

Lists of major support companies have been presented in several studies (Table 13). Most of these companies lease existing commercial space in frontier area harbors. They cluster together at the same harbors as support bases. Petroleum companies coordinate storage and shipment of supplies to offshore facilities. If a major new shore support base is constructed, many general support firms could lease space within the base. This locational relationship offers the most cost-effective operation. In developed harbors, where the service base uses existing facilities, general shore support companies will rent space near the base.

Table 13. Major OCS Support Companies and Average Employment Figures (Source: Reference 28)

Company	Average Employment
Mud Supplier (drilling mud)	13
Wireline Company (for drilling)	15
Gas Lift Company	5
Logging and Perforating Company (testing)	10
Welding Shop	23
Rental Tool Company	10
Fishing Tool Company	9
Wellhead Equipment Company	12
Machine Shop	9
Trucking Firm	15
Cementing Company (cement for drilling)	12
Supply Store	9
Downhole Equipment Company	11
Other (includes onshore catering support)	96
Total Employment	260

Each company is characterized by small labor requirements, using small to medium-sized equipment and being physically indistinguishable from other marine support activities on the waterfront. General shore support companies can be placed in one of three groups. The first group has a shorefront headquarters, but works primarily offshore. Companies in this group, such as a diving service, use their onshore base for equipment repair and administration.

The main function of the second group of companies is to assemble or modify products onshore for use in offshore facilities. This diverse grouping including catering services, machine shops, and mud suppliers, require more onshore space for administration, production, receiving and shipping.

The third grouping includes those firms which do not process products, but rather assemble, store and ship items offshore when needed. These companies, including the supply store and rental tool company, require warehouse space.

Site Requirements

For many companies, such as a diving service, a waterfront location with wharf and waterfront space is required. Other companies, such as a rental tool company, can merely locate where they have good access to the waterfront area and support base. Location flexibility is tied to the bulk of items supplied offshore. A company shipping large volumes or bulk items, such as the mud supplier, will locate adjacent to the harbor, with access to rail, road and water transportation, while companies responsible for small component items, such as a catering service, can locate in the general vicinity of the harbor. Other factors, including startup and operating costs, will have a major influence on site selection by these firms.

Operations

General shore support companies receive materials destined for offshore facilities, and store and/or modify the materials until they are required offshore. Offshore rigs and platforms have limited storage facilities. Operating characteristics relate closely to services provided, and the total effort needed to make the contracted services and materials available on demand offshore. In general, shore support businesses are similar to a warehouse supporting heavy construction activity, with large supplies of necessary materials stockpiled and most activity associated with moving it or modifying it to meet specific offshore needs.

Community Effects

General shore support encompasses a variety of specialized companies serving the offshore industry. Each company will provide a few local employment opportunities, normally in the general labor category [19].

Construction/Installation

Onshore support firms use existing space and facilities. With the possible exception of the mud supplier, installation and construction activities for individual firms are insignificant. Collectively, however, they may have an effect on a single harbor. In a frontier area, if a new service base is constructed, it is likely that many general support facilities will lease space within the service base.

Employment: Employment data for 15 to 20 representative companies involved in shore support is presented in Table 13. Employment in each firm includes three categories: specialized skills, general labor, and administrative staff. If all potential firms moved into a single area, the effect on local employment and commercial space would be significant. Therefore, it is important to understand conditions under which individual firms prefer to locate in the adjacent onshore area rather than service offshore operations from a distance. Table 14 lists threshold values, as expressed by the Offshore Operations Committee, for selected support companies in one frontier area, the Mid Atlantic lease sale. If these companies move into an area gradually, they will have less impact on local employment over a longer term than most other facilities associated with OCS development. Major impact could occur if a large number of firms establish new facilities in a small area within a limited timespan.

Induced Effects: Induced effects may be important from an employment perspective, but should be negligible in terms of facility needs at the site. Each company will bring at least some administrative staff from established facilities. Individuals in these higher paying jobs as well as other employees with special skills brought in by the firm, will require housing and local services.

Effects at the site will be negligible because requirements are small in terms of service demands, and firms will try to locate in vacant commercial space. Most of these firms have limited investment capital and prefer to conduct their operations in leased facilities. This strategy reflects the lifespan of an oil field, the specialized nature of most support services within the phases of OCS activities, and the fact that purchase of the property would mean a need to sell when the shorefront commercial land market is depressed because the offshore field is shutting down.

Effects on Living Resources

General shore support companies have the following characteristics of particular fish and wildlife concern: (1) many and small acreages for industries ancillary to the major oil companies; (2) berths, channels, piers and bulkheads; (3) storage areas; (4) service areas and operations shops; (5) administrative buildings; and (6) parking lots.

Table 14. Industry Estimates of Onshore Facility Requirements for OCS Oil and Gas Operations in the Baltimore Canyon (Source: Reference 36)

Stimulus	Number of Facilities Required for Full Development of Region	Company Type
minimum of 10-20 rigs working to establish one facility (10-20 rigs could attract 2 to 3 facilities)	5	Mud Suppliers Wireline Company Gas Lift Company Logging and Perforating Company Cement Company Supply Store
minimum of 10-20 rigs working to establish facility	up to 10	Welding Shops Machine Shops Fishing Tool Company Rental Tool Company
minimum of 10-20 rigs working to establish facility	3-5	Wellhead Equipment Supplier
minimum of 10-20 rigs working to establish facility	6	Downhole Equipment Companies
minimum of 10-20 rigs working to establish facility	5 in addition to existing facilities	Machine Shop
minimum of 10-20 rigs working to establish facility	2 in addition to existing facilities	Trucking Firm
minimum of 10-20 rigs working to establish facility	Not more than 1	Diving Service

Location: For some of the general shore support industries a waterfront location will be necessary to have raw materials and supplies arrive and depart by barge or ship. This will mean that piers, floats, and dolphins will have to be constructed and berths and channels dredged. Dredging should be performed only with protective devices, such as sediment screens, and by techniques that keep sediments to a minimum, such as working only on the outgoing tide. Existing facilities should be adapted to accommodate these many small industries. The location of these facilities at the entrances of harbors and rivers with significant flushing rates will aid in the dispersal of propeller-generated silts and sediments. Additionally, erosional runoff from unpaved storage areas and parking lots will be more quickly transported rather than settling in adjacent salt marshes, clam flats, etc., where organisms could be smothered. Industries that have no direct coastal connection should be situated on the upland. Wetlands should not be filled to obtain new area because of the loss of vital fish and wildlife habitat.

Design: Where general shore support industries have service areas and operations shops, grease and oil traps should be installed and properly maintained. This will reduce the amount of petroleum products reaching runoff water. All cooling water that may have contacted petroleum or other contaminant material should be treated before it is allowed to re-enter natural water bodies. Compressors and other equipment, which may exceed acceptable noise levels should be housed or provided with muffler devices to reduce the sound levels. Bulkheads should not be used as substitutes for piers. Solid fill bulkheads interrupt littoral drift and cause sand to be diverted from downshore areas which were previously supplied by the along-shore currents.

Construction: Heavy equipment must be scheduled to avoid operations during sensitive periods of fish and wildlife cycles, such as spawning/breeding, rearing, etc. Erosional sediments from runoff may cover fish eggs causing failure to hatch, while noise and other disturbances may be disruptive, especially in or near endangered species habitats. If construction is to occur in wetlands, the heavy equipment should use construction mats to protect the area from long term damage by tractor treads, truck wheels, etc. Existing service roads should be utilized as much as possible and should be strengthened to accommodate the loads of heavy equipment.

Operation: If oil or gas is to be stored above ground on the premises for operations, dikes around the tanks should be able to accommodate the full contents of the tanks. Each tank should have its own access road and the tops of dikes should not be used as service roads or be traversed by vehicles that could erode surfaces. All waters involved with processes should be collected in a central system for treatment, such as aeration, precipitation, etc., to reduce pollution loads when the water re-enters the natural water course. Operations that create

dusty or dirt-laden air should be enclosed and utilize dust-bags or other devices to prevent local problems with air quality.

Regulatory Factors

State and local permits and certifications required for shore support facilities will be dependent on which required facilities are already available. The development or expansion of new facilities will require new permits dependent on their size and location. The general description of state and local programs in Section 2.1.3 indicates the nature of permits and certificates commonly required.

Federal Role: Federal permits for new construction affecting wetlands or requiring maintenance or channel dredging would be issued by the Corps of Engineeers. The procedures and comment functions of the Fish and Wildlife Service are described in sections discussing Platform Fabrication (2.3.4) and Service Bases (2.3.1). Other Federal permits may be required dependent on the nature of the facility. The list of Federal programs dealt with by programs of the FWS in Section 2.1.3 illustrates the concerns a sponsor must consider.

Development Strategy

The strategy of the shore support firm is based upon attaining a threshold level of potential business offshore. If demand is less than the threshold level, which varies greatly among this diverse group of firms, a firm will ship its products or conduct its operation from an established base. Thus, if a single COST hole is being drilled prior to leasing, muds, pipe and all other necessary materials are shipped in from established bases, even though quite distant.

As a frontier field passes through the exploratory phase and commercial quantities of petroleum are located, additional support companies find it financially advantageous to locate in the frontier harbor area adjacent to or within a supply base. The threshold is reached when a firm can reduce its total costs, which include transportation, processing, and administration, by locating in the frontier port area.

In a frontier area harbor with a support base, there usually will be only one firm contracted to perform each specialized function. Probable exceptions are trucking firms, machine shops, and welding shops. If firms have no competition, they have much greater locational flexibility and can attempt to minimize costs rather than maximize potential business in selecting a site.

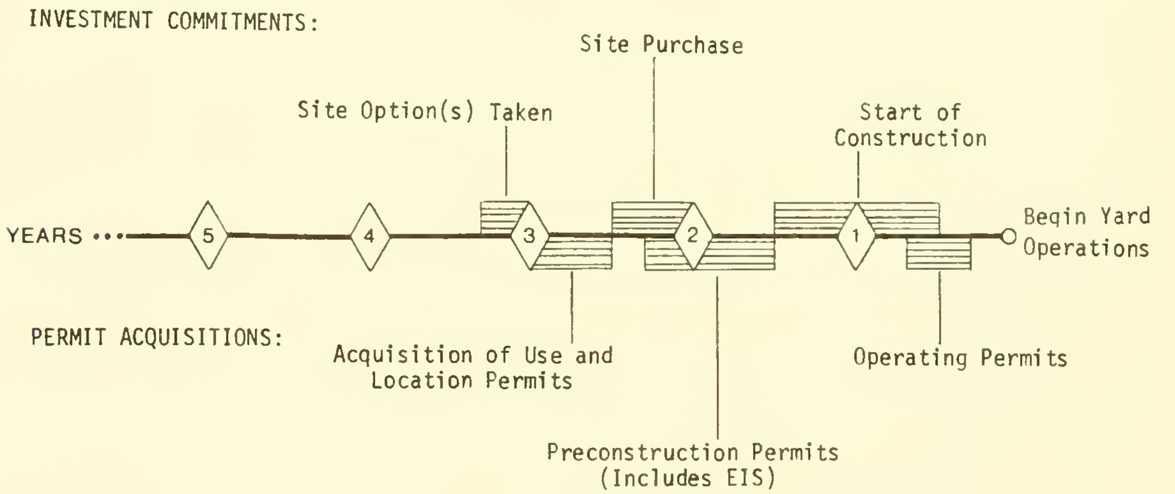
The strategy of these firms is independent of petroleum company field leasing and development strategy. These firms follow petroleum companies into frontier areas. Such support firms monitor all petroleum company activity trends as their viability depends on continued contracts. About half of the businesses cited earlier in this section, such as a downhole equipment company, sense the specific needs of the petroleum industry.

The remaining firms either serve the petroleum industry as one of many customers or are already located in the frontier area to serve other commercial enterprises. For these firms, the initiation of OCS-related activities means new contracts and an increase in business. These businesses will merely expand to accommodate the special needs of the petroleum industry.

2.3.4 Platform Fabrication Yards

Production platforms are installed offshore to support drilling and production operations and to provide crew housing and supply storage (see Figure 33). The types of platforms currently in use are fixed-pile platforms, usually made of steel, and gravity platforms, made of steel or concrete and held to the bottom by their own weight supplemented with ballast. Platforms are composed of a superstructure called the "jacket", and "deck" for drilling operations which sits on top of the jacket. They are described in Section 2.2.3 -- Production Drilling.

Figure 33. Platform fabrication yard - project implementation schedule.



The fabrication of these immense structures and the platform jackets is done in specialized facilities known as platform-fabrication yards. These yards have the highest impact on coastal environments of any onshore facility required by offshore oil and gas development. A fabrication yard requires more land on the waterfront, more heavy industrial materials, and a much larger labor force than any other onshore project. Due to the extensive requirements of a fabrication yard, it will invariably become the nucleus of numerous ancillary service and supply companies--welding supply, marine repair, and heavy equipment sales.

Within the United States there are four large fabrication yards which receive all the major platform business. Three of these are on the Gulf Coast where the bulk of U.S. offshore activity has long been concentrated, and one is on the Pacific Coast. Two of the Gulf Coast yards dominate the U.S. platform fabrication business -- Brown and Root, whose yard is near Houston, Texas, and J. Ray McDermott, whose yard is just east of Morgan City, Louisiana. The third Gulf Coast yard, operated by Avondale Ship Yards, is also near Morgan City. The fourth major U.S. yard serving the west coast market is owned by Kaiser Steel Corporation at Oakland, California. Each of the Gulf Coast yards occupies about 1,000 acres of land, and each has the capacity for building two or more platforms simultaneously.

The Gulf Coast yards have fabricated platforms for both the U.S. and international oil and gas drilling. Approximately 20 percent of Brown and Root's production of platforms from their two Gulf Coast yards are for foreign countries [37]. The few platforms installed in Alaska have been built in the "lower 48." Kaiser has built at least six of the 14 platforms located in the Cook Inlet area of Alaska [38].

The Kaiser yard recently completed the world's largest platform superstructure (jacket), which has been installed in Exxon's Hondo field in the Santa Barbara channel--it is 865 feet high and installed in a water depth of 850 feet which is nearly twice the depth of any other offshore jacket. The total height of the Hondo structure is 945 feet.

Unless the demand for platforms in new U.S. frontier areas is heavy, based on large finds, their fabrication can easily be handled in the four existing major yards. Two large yards have been proposed by Brown and Root: a 980 acre site at Cape Charles (Northampton County), Virginia [39], and a 400 acre site at Astoria, Oregon (to be operated by a Brown and Root subsidiary, Pacific Fabricators, Inc.). These facilities were proposed recognizing the lengthy process preceeding construction and in anticipation of possible large finds in offshore frontier areas. Each proposal includes a dry dock so that large, self-floating platforms can be fabricated. These yards could both begin operations in 1978 and ultimately have an employment of 1,200 people or more. Both yards were initiated (i.e., land optioned) before leasing and exploratory drilling occurred.

Description

Fabrication yards occupy from 200 to 1,000 acres of cleared level land adjacent to a navigable waterway of adequate depth (usually 15 to 30 feet). Major facilities may include a dry dock (graving dock), jacket-fabricating area, pile-fabrication rack, deck- and modular-assembly building, pipe-rolling mill, plate and pipe shop, painting and sandblasting shops, electrical shops, and warehouses. Approximately 60

percent of the yard area is used for welding large tubular steel jackets; fabrication work areas are adjacent to bulkheaded shorelines, except where a large dry dock (graving dock) is installed for final assembly of the largest self-floating jackets. The remaining 40 percent of the yard area is used for: storage of steel plate and structural sections which are cut, rolled, bent, and welded into prefabricated partial units; parking lots and administrative buildings; the welding and machine shops; and the large hangar-type deck-fabrication buildings. Figure 34 shows the site plan for the proposed platform-fabrication yard at Cape Charles in Northampton County, Virginia.

Site Requirements

The site requirements for a fabrication yard include the availability of a skilled labor pool, access to established transportation networks, access to high voltage power, a large flat site with adjacent deepwater channels, and a sheltered harbor.

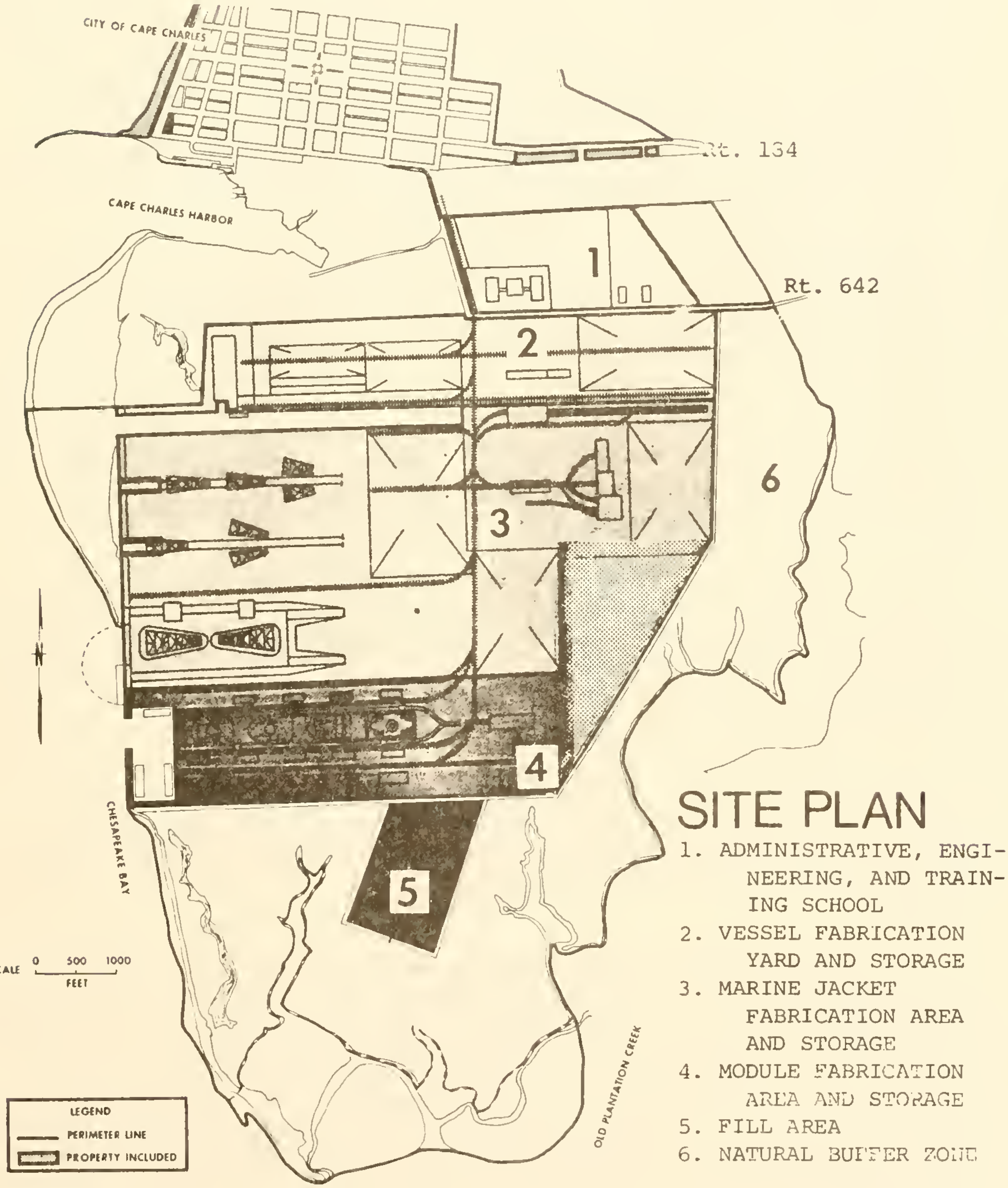
The required length of the wharf depends on the number and size of the platforms (steel) being constructed at any one time. Since the jacket is constructed perpendicular to the wharf, the length of the wharf is determined by the base height of the platform and the number of platforms lined up at the waterfront [26].

The required water depth at dockside and in the channel varies with the type of platform being constructed. For fixed-pile platforms, a depth from 15 to 30 feet is normally required. For gravity platforms, particularly cement gravity platforms, much deeper water is required. Once the concrete base is completed in dry dock, the base is floated and moved away from dockside to depths of from 240 to 300 feet. This deepwater site must be sheltered and within a few hundred yards of the fabrication yard.

The smallest facility producing platforms is 50 acres, but larger yards require between 200 to 1,000 acres, with 300 acres the average. Some yards are considerably larger. Brown and Root's proposed Virginia site is 980 acres, of their total land holding in the area of 2,000 acres. The availability of the land can have important effects on the size of the yard, initially as well as later on when expansion is considered. If the land at the chosen site is abundant and inexpensive, the sponsor will likely option or purchase a larger parcel than if the availability or price was restrictive [26].

For steel platforms the channel width should be up to five times the beam of the largest barge to be towed from the fabrication yard. The average beam of such barges is 60 feet; therefore, the channel width is usually 300 feet. Because of the difficulties involved in towing gravity platforms (such as clearance requirements, weight and height),

Figure 34. Site plan for Brown and Root platform fabrication yard at Cape Charles in Northampton County, Virginia (Source: Reference 39).



concrete fabricators prefer not to navigate a channel to reach their deepwater construction site.

The average required clearances for both the vertical and horizontal dimensions in the access route from the fabrication yard to the open sea are from 210 to 350 feet, depending, of course, on the size of the platform and the required margin of safety [40]. Where bridges can be opened, horizontal clearances should also be determined. Vertical clearance requirements for gravity platforms are much greater than for steel platforms. Since pillar and superstructure heights can exceed 400 feet, bridges of any kind are probably unacceptable [26].

The transportation of raw materials, personnel, fuels, stores, equipment, and machinery and parts for a fabrication yard is likely to require all four principal forms of transportation--air, road, rail, and sea. The magnitude of traffic will vary with the type and number of platforms under construction. The volume of raw materials required for a cement gravity platform, for example, can be as much as ten times that required for a steel platform. If a spur line is available or constructed, a two-platform cement yard could require three train deliveries per day for raw materials (aggregate, cement, steel). Also required would be two rail tank cars per week for fuel and lubrication oils and one rail car per week for machinery and spare parts [26].

If a source of raw materials is available near a waterfront site, cement-platform yards would be likely to receive the materials by barge--an estimated two to three 3,000 ton barges would be required every two weeks. Generally, because shipping is the least expensive transportation alternative, fabricators will ship major materials to the yard if at all possible.

In contrast to the broad range of potential steel-jacket-platform sites, the choice of a concrete-gravity-platform fabrication site is largely dependent upon proximity to the drilling site. Concrete-gravity-platforms are too heavy and massive to be towed long distances; if they are to be used in Alaska, they will have to be constructed in Alaska.

Since platform-fabrication yards employ hundreds of skilled iron workers and welders, a sponsor will attempt to locate in the vicinity of a labor pool which has an abundance of these skills. Areas with existing ship repair and construction yards have available welders and other skilled craftsmen in the work forces. However, many of the skilled workmen and management staff may be imported from existing Gulf Coast fabrication yards, to provide a nucleus of personnel who know and understand the fabrication business. In order to accommodate the total workforce required (up to 1,200) a sponsor will also attempt to locate near a community capable and desirous of accommodating industrial-based growth.

Construction/Installation

The first step is preparation of the fabrication site itself, including dry dock, road and rail spurs, yard, dockage, and storage areas. Site preparation can take as much as three months to a year, depending on the size of the facility [26].

When ready for fabrication, the site should be 5 to 15 feet above mean high water in adjacent navigation channels. The waterfront site required for a fabrication yard may involve a high probability for wetland and shoreline alteration in the construction of the facility. Most of the site will be cleared of vegetation and graded by large earthworking machinery. Parts may require being filled and stabilized with sand and gravel from adjacent waters or lands. Existing channels may have to be deepened or widened to provide a turning basin and access to deepwater channels for marine traffic--barges, tugs and platforms.

Operations

Steel platforms are made up of two sections--the deck and the jacket. The jacket serves as a base to support the deck section. The jacket is composed of huge steel tubular members welded together to form a stable base. When completed, it is rolled on dollies or rails onto a launch barge and towed to the installation site.

The deck section includes the drilling and production facilities, living quarters, helipad, and whatever else may be required, depending on the complexity of the platform. The deck section and its attached units are built in large construction sheds, sometimes in distant areas. Wherever completed, the deck section is barged separately out to the installation site.

Gravity Platforms: The assembly of gravity platforms differs markedly from that of fixed platforms. Since there is little difference between steel or concrete gravity platforms, apart from materials involved, the focus here is on concrete platforms.

The base of the platform, usually composed of many cylindrical prestressed concrete cells, is constructed vertically in a dry dock (graving dock) immediately adjacent to deep water (150 to 300 feet). When completed, in about nine months, the gravity platform is floated out of dry dock; its ballast cells are filled, and the base section is partially submerged to permit further vertical construction. If the platform is to be used in shallow water, all that is necessary at this point is to affix a deck section to the base and to add the appropriate drilling, operations, storage, and living quarter modules; then the platform is ready for deployment. However, since concrete platforms are more often used in very deep water, huge concrete pillars, or towers, are constructed atop the partially submerged base section. The con-

struction of these pillars can take from 9 to 15 months. At this point the fabricator is likely to tow the concrete structure to even deeper water (100 fathoms) to give it a submergence test prior to installation [26].

Community Effects

A fabrication yard has the following characteristics of particular interest to the community: (1) potential for high employment and community growth; (2) potential for high investment and a broader tax base; (3) large parcel of land involved; (4) high service requirements and (5) extensive commerce in raw materials.

Employment: The construction of a platform-fabrication yard will require approximately 500 laborers; up to 1,200 people will be hired to construct platforms. Employment will vary greatly depending upon the number of platforms and jackets under construction at any time. As many as 90 percent of these workers will be local residents. The presence of a major new industry will attract unemployed individuals who will also compete for jobs. Most jobs are for fabricators and welders who can be trained locally if necessary skills are not available. Activities in adjacent and nearby communities to support these workers and their dependents--home construction, increased commercial activity, and demands on public services--are a potential source of disturbance to fish and wildlife resources and habitats.

Induced Effects: Analysis of a fabrication yard proposal illustrates the potential scale of effects. Requirements of the proposed Brown and Root fabricating yard in Northampton County (Chesapeake Bay eastern shore) in the State of Virginia indicated the following estimated effects: 1,670 new residents; 125,000 square feet of new commercial space; increased demand for domestic water supplies of 850,000 gallons a day; increased sewage load of 600,000 gallons a day; increased student enrollment of 1,100; and increased solid waste disposal of 15,000 tons per day [39]. In more rural environments, where these facilities are likely to locate because of the large parcel of shorefront land required, disruptions of this magnitude on services are substantial.

Effects on Living Resources

A platform-fabrication yard has the following characteristics of particular concern to fish and wildlife: (1) waterfront location; (2) large use of coastal land area; (3) possibility of wetlands filling; (4) dredging of shipping channels and spoil disposal; and (5) possibly dry dock (graving dock).

Location: A platform-fabrication yard must have a waterfront location. While this location need is common to other industries, the

important factor in this case in the amount of fish and wildlife habitat that may be displaced in establishing a yard. Although there are few yards larger than 1,000 acres, the siting of a facility may utilize a large amount of coastal land and therefore have significant consequences for local habitats. Large acreasges of coastal upland for a facility of this type are usually unavailable; the unfortunate alternative is the extensive filling of wetlands.

Design: To service a platform-fabrication yard, it is necessary to design navigation channels and a turning basin for launching platforms when completed. The dredging of new channels or the deepening of existing ones will create turbidity and sedimentation in the water and may lead to the smothering of organisms, such as clams and corals. It may also cause reduced photosynthesis because of the decreased penetration of sunlight. If spoil disposal sites are selected too close to sensitive species habitats, there may be detrimental effects on indigenous species from the dumping of materials. If concrete platforms are to be constructed, a large dry dock (graving dock) will need to be excavated. The Corp of Engineer's Dredge Material Research Program has developed guidelines and techniques to reduce the effects of dredging and disposal operations which include turbidity-reduction dredge types, operational techniques and scheduling tables [41].

Construction: With the need for platform yards to be relatively flat,the major construction activity is alteration of the topography into a flat area. Large open areas are needed for storage of raw materials for the platform-fabrication sections, so vast areas are cleared of vegetation. This causes a drastic change in the microclimate of the area making it uninhabitable for the wildlife species which previously occupied the sector. With the vegetation removed, erosion may occur if appropriate measures are not taken to control it. Without proper control there may be excessive sedimentation into streams and rivers producing degraded fish habitats.

Operation: The applicant's major environmental problems in operation will be meeting EPA pollutant-discharge standards on waste disposal and runoff water; other environmental problems will involve maintenance and the disposal of dredge spoil.

Regulatory Factors

A platform-fabrication yard requires an onshore site of substantial size. Access to open water, demands for electricity, raw materials, transporation, and water for industrial use also pose potential regulatory problems. The onshore site is likely to be subject to Federal, state, and local regulations setting conditions for different aspects of construction. In general, a site in an existing industrial area will receive less regulatory scrutiny from local government than one located in residential or undeveloped natural areas.

State Permits: Most states have regulations requiring a permit for alteration or filling of wetland areas. Other state-level concerns include utility planning for high voltage electrical service, and air- and water-quality regulations governing industrial processes. In some states large scale development may also trigger a state permit or review process. The 1976 Amendments to the Coastal Zone Management Act require special planning elements for states that wish to qualify under its provisions. These plan elements, once approved by the Office of Coastal Zone Management, may influence Federal decisions as Federal actions must be "consistent" with the approved state program.

Local Permits: Unless a fabrication yard is located in an area where industrial development is already permitted, zoning approval for industrial uses will be required from a local government unit. The requirements of zoning regulations vary from one community to another, and zoning permission may be denied as a matter of local policy at any time before a sponsor begins construction. Other local permits referred to in Section 2.1.3 are less likely to be encountered or to pose substantial obstacles to development.

Federal Role: The waterfront location required for platform fabrication ensures Federal involvement in the development-approval process for dredge and fill permits before wetlands development or channel maintenance. The Corps of Engineers manages the permit program under the authority of Section 10 of the Rivers and Harbors Act and Section 404 of the Federal Water Pollution Control Act Amendments of 1972 in partnership with the Environmental Protection Agency. Court decisions have extended the limits of Corps implementation efforts from the "navigable waters" governed by Section 10 to the "waters of the United States" governed by Section 404. With exceptions related to the size of the lake or stream and agricultural use, permits are required for activities in all wetlands and water areas.

Implementation of dredge and fill regulations takes place at the District Engineer level along with the participation of the Regional Office of the Fish and Wildlife Service and the Environmental Protection Agency. The Corps must request the advice of the Service on every application. If the Regional Director of the Fish and Wildlife Service files a timely objection to permit issuance, the matter is first referred to the Corps' Division level for review, and unless the objection is withdrawn, then to Washington to be settled between the offices of the Secretary of the Army and the Secretary of the Interior.

The Fish and Wildlife Service advises and comments on wildlife and habitat and possible mitigation actions which will reduce the impact of a proposed project on them. Other specific authorities add to FWS responsibilities in Federal permit review. Regulations governing the Corps of Engineers procedures are found in 33 Code of Federal Regulations Section 209. The Fish and Wildlife Service operates under a separate set of procedures described in Volume 40 of the Federal Register, page 55810, published December, 1975.

The Fish and Wildlife Service is primarily responsible for the implementation of the Endangered Species Act. This act prohibits destruction of the habitat of certain listed plant and animal species by Federal agencies or under Federal permits.

Development Strategy

Platform-fabrication yards are built by companies that specialize in the construction and erection of offshore facilities under contract to the oil companies (which are the offshore operators). Yard sponsors stay in close contact with the offshore operators to ascertain future regional demand for platforms. By comparing the anticipated demand for platforms with the capability and location of existing yards, the fabricators can evaluate the needs for additional fabrication yards to serve new demands in developing fields. As previously stated, unless there are major finds, there will be no additional major platform yards.

Among the most important considerations are: (1) an estimate of the demand for platforms and the timing of that demand; (2) the location of the find, therefore, the type of platform likely to be in demand; (3) an estimate of the portion of the market that can be captured; (4) labor availability and restrictions; (5) proximity to the find and, (6) water depth and climatic conditions in the frontier area.

Basically, the fabricator desires to find a reasonably sized and situated tract of level land within economically practicable distances from the offshore installation sites, that also has close access to water of sufficient depth to allow movement of the platforms from the yard to open water and on to the installation site.

In addition to the unpredictability of demand by new fields, the excessive overbuilding during the past few years of both tankers and mobile drilling rigs caused a sharp downturn in the U.S. and worldwide shipyard activity. This downturn, expected to continue through 1980, has freed shipbuilding facilities to convert and to enter the platform-fabrication business, thus potentially reducing the need for new yards.

The strategies of the offshore operators and platform fabrication sponsors are largely but not totally compatible. The sponsor wants to limit investment in the yard until an initial contract order is signed. Therefore, the sponsor would prepare all engineering studies and would acquire all permits for yard construction but would not initiate construction activities. On the other hand the offshore operator would benefit from the maximum development of the yard prior to contract orders so that production can be initiated at the earliest possible time after confirmation that recoverable quantities of oil exist under the OCS site.

Offshore operators and platform fabricators have a mutual advantage in having a yard ready for production soon after a commercial-sized field is found offshore; the sooner drilling and production can begin, the sooner the operator can begin to earn a rate of return on the vast sums already invested in lease payments and exploratory drilling. By having a yard ready for operation when orders for platforms are received, the fabrication firm can assure early delivery and thus can compete favorably with other firms for the business.

The platform sponsor generally, though not always, makes the decision to establish a strategically located yard after a significant find has been made and its development schedule has been set.

The sponsor may speculate on future sites. Even before lease sales occurred, Brown and Root purchased land in Virginia and optioned land in Oregon without making a commitment on a yard.

While the oil company is in the process of delineating the field within which the find has been made, the platform sponsor will hold meetings with oil company representatives to estimate the number of platforms that might be needed to draw up a possible schedule for delivery, and to draw up preliminary design specifications for platforms as the nature of the field is determined. Other information likely to affect the choice of platform type might include location of the find, the seabed conditions, the depth of water, and other requirements. The choice of platform type will determine the amount of lead time required for obtaining steel and manpower.

To summarize: a platform fabrication yard is usually sited and planned well in advance of offshore production drilling, and the platform-fabrication companies may obtain an option to buy or lease a suitable tract of land well in advance of an offshore lease sale; the fabricator may not act on this option until he is assured of platform orders. An option allows the fabricator to proceed with environmental impact statements, zoning applications, site layout, design of facilities, and applications for building permits; having accomplished these preliminaries, the fabricator is ready to rapidly construct the yard once a platform order is received. Once an order is received economic forces and the rush to develop the newly discovered field causes a burst of activity with momentum that may not easily accommodate environmental concerns.

At the time of taking land options environmental considerations can be easily incorporated into the plan for the fabrication yard. The ability to insert environmental recommendations continues to the time a platform order is received.

Investments: Securing an option on land and initiating environmental studies and designs of yard facilities does not assure that the yard will become a reality. Until the market for platforms has firmed up, a new platform yard may not be constructed since at least three large

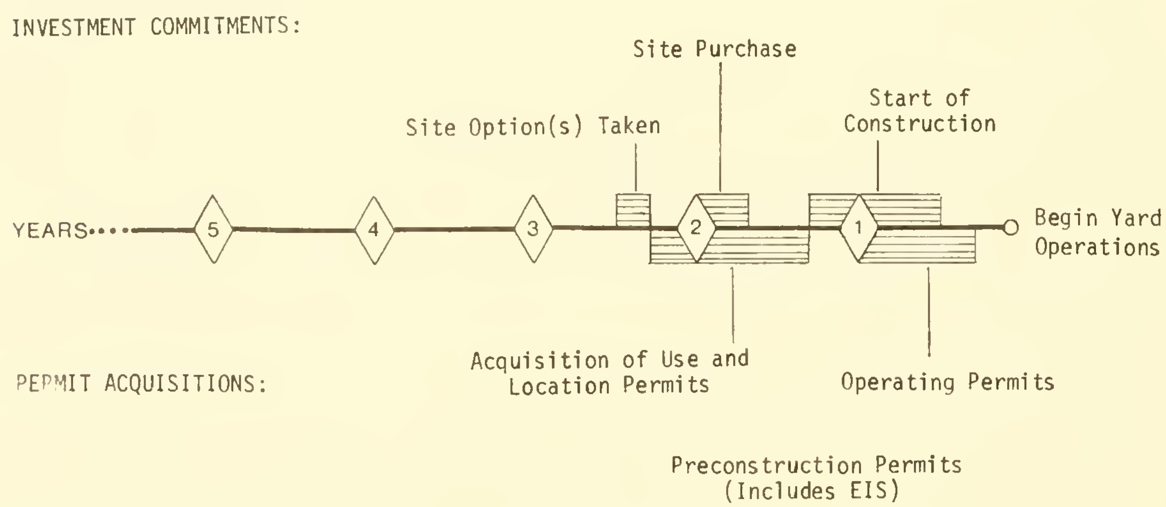
platforms must be built before a new yard will return a profit. Advance money spent on the above simply gives the sponsor an advantage over his competitors when a platform is finally ordered. Though the sponsor may invest up to $1 million in preliminary work, this is only a fraction of the price of a completed steel-fabrication yard, which may cost from $20 to $40 million, or of a large deepwater platform fabrication yard, which can exceed $100 million. Long transport distances weigh in favor of a new yard, but the high capital costs of a new yard tend to favor fabrication at existing yards.

2.3.5 Pipe-coating Yards

The pipe-coating yard is one of the more significant OCS related onshore developments that will occur during the recovery of oil and gas. When an oil or gas field having commercial potential is delineated, a decision is made concerning the mode of oil or gas transit to shore for processing. The preferred mode is very often pipelines because: (1) fewer transfer operations occur compared to tankers; (2) pipelines operate efficiently in all types of weather; (3) pipelines have a better safety record than tankers; and (4) a direct, continuous stream of oil or gas passes to the onshore refinery or gas processing plant.

The laying of a pipeline is complex and requires special techniques for successful operation; coating is one of these special techniques. The pipe-coating yard applies a cement coating to the pipe for two purposes: (1) to protect the steel pipe from the corrosive elements of sea water, and (2) to add sufficient weight to overcome the buoyancy of the lighter oil and/or gas (See Figure 35). The technique and the intricacies of laying pipe underwater have led that operation to be one

Figure 35. Pipe-coating yard, project implementation schedule.



of the most costly in the oil and gas industry. The costs for underwater pipe-laying can approximate $1,000,000 per mile and possibly more in rough terrains. Therefore, it is imperative to give as much protection to the pipe as possible to prevent costly failures of the pipeline (e.g., leaks, bends, ruptures) due to seismic activities, improper burial, inadequate weld, or excessive currents and tides.

Description

A pipe-coating yard occupies approximately 75 to 200 acres, the bulk of which is used for pipe storage. A relatively flat piece of land that has good rail and water access is necessary for efficient operation. Forty-foot lengths of pipe are generally brought to the yard by rail (or by truck or barge); after being coated the weighted pipes are shipped by sea to a waiting pipe-laying barge. The main components of a pipe-coating yard are:

- Pipe-cleaning buildings
- Pipe-coating buildings
- Outdoor storage space
- Supplies storage buildings
- Rail terminal
- Marine terminal and bulkhead
- Administrative offices
- Maintenance and repair buildings

Site Requirements

The location of a pipe-coating yard has traditionally been in a coastal area to utilize the marine connection to offshore operations. A marine shipping terminal is a necessity for loading and unloading materials. Uncoated pipe may arrive by barge, but when the coating has been applied, the pipe must be shipped by boat to the offshore lay-barge. Raw materials, e.g. pipe and cement, will typically arrive by land routes. Therefore roadway and rail access are other criteria that must be satisfied in site selection in addition to navigation channels.

Construction/Installation

Typically a pipe-coating yard must be situated on solid soil of high load-bearing capacity because of the many activities involving heavy equipment. With location of the yard in a coastal region, there is a good probability that wetlands may be involved at some point in construction. The land must be cleared of vegetation, and "soft spots" must be excavated and filled with either sand or gravel to maintain an acceptable working surface. Heavy equipment would be employed to rework

the land area for storage, while other parts would be utilized for the construction of the pipe-coating plant and other buildings. Pipe-coating may be done outside, depending on weather conditions and steps involved.

The construction of the marine terminal for pipe receiving and shipping would involve the dredging of berths, a turning basin, and a navigation channel (15 to 30 feet deep). The projects could be done with a variety of machinery from dragline to hydraulic dredges. If the dredged material is sand, gravel, or oyster shell, it could be utilized for filling or surfacing the land areas, but dredge material of loose, unconsolidated mud and clay would need a disposal site. A bulkhead several hundred feet long would have to be constructed to accommodate ships and barges loading and unloading pipe and materials.

Operations

The pipe-coating process has two major components: (1) the application of an anti-corrosion (mastic) coating and; (2) the application of a weight (concrete) coating.

Pipe first enters a cleaning building where it is scraped, brushed, and sandblasted to remove rust and to yield a good, clean surface for the anti-corrosive coating. The anti-corrosive coat is applied as a hot, asphaltic mixture after which the pipe is cooled by water to reduce the temperature and yield to a smooth mastic. Hydrated lime is added to the freshly coated pipe to assist cooling and to prevent sticking when pipes are stored. Electronic and other inspections determine if the anti-corrosive coating is uniform and ready for the next step. Care must be taken not to damage the newly applied coat.

Concrete is applied as an outer layer by being sprayed at high speeds and by adhering to the rotating pipe giving a thick coat. Galvanized wire wrapped around the pipe provides adhesiveness. Weighing determines if the pipe will meet the proper specifications (140 to 190 lbs. per cubic foot) for the intended use. When finished, the pipe is placed unstacked on sand rows to allow adequate curing, after which the coated pipe is ready to be loaded onto a supply boat. The boat carries the pipe from the marine terminal to the offshore lay-barge where the pipe-laying operations are conducted.

Community Effects

A pipe-coating yard requires about 100 acres (primarily for storage), a waterfront location or access to a marine terminal, a level site with compacted soils, and access to transporation systems. It would probably be located outside an urban area because of land costs, but it needs access to a wharf or pier.

Employment: A pipe-coating facility processing 200 miles of 30-inch pipe (26,400 joints) in eight months might employ up to 200 people. This business has "boom or bust" characteristics so that employment will come in spurts and will vary in size in response to specific orders perhaps dropping to 30 to 40 people in slow periods. Only a small number of supervisory personnel will move into the area; the remaining employees will be local [26].

Induced Effects: One study has described a pipe-coating yard as being similar in area and impact to asphalt-paving and construction supply yards of comparable size [21]. Required services at the facility, including water, sewage, solid waste disposal, and protection, will add little in cost to the community. In addition, as only a few employees will be new to the region, residential-related increases in service demands will also be minimal. Unemployment benefits between contracts may be a much more significant expense at the state level.

The pipe-coating operation results in airborne particulate matter. The stored pipe is unsightly, and an empty barren yard may or may not be an improvement. These factors could adversely affect adjacent coastal property values. This adverse effect might more than offset benefits to the local economy.

Effects on Living Resources

A pipe-coating yard has the following characteristics of particular concern to fish and wildlife: (1) water and rail access; (2) large storage area; and (3) water runoff.

Location: Although a pipe-coating yard could be located at an inland site, it is generally located near a waterway to make use of that transportation mode in handling bulky and heavy pipe lengths. The location also provides immediate access to offshore drilling activities which could only be reached with more difficulty from an inland site. Requirements for a coastal location and a large acreage for storage make the filling of wetlands a distinct possibility.

Design: To service a pipe-coating yard it is necessary to design navigation channels and possibly a turning basin to accommodate ships and barges. The dredging of new channels or the deepening of existing ones will create turbidity and sedimentation in the water and may lead to the smothering of organisms, such as clams and corals, and to reduced photosynthesis because of the decreased penetration of sunlight. If spoil disposal sites are selected too close to sensitive species' habitats, there may be detrimental effects on indigenous species from the dumping of materials.

With the need for a large tract of relatively flat land for pipe storage and curing, storage areas should be designed to occupy upland

sectors to avoid the filling of wetlands and the loss of valuable fish and wildlife habitat used for breeding/spawning, rearing of young, and food production.

Construction: With the necessity for pipe-coating yards to be flat, the major construction activity is the alteration of the topography into level land. This requirement will cause large acreages to be cleared of vegetation and will cause a drastic change in the microclimate of the area. Species which previously occupied the sector will now find the area uninhabitable. Also, with the vegetation removed, erosion may occur if appropriate control measures are not taken. Without proper control there may be excessive sedimentation into streams and rivers producing degraded fish habitats.

Operation: The operations of cleaning and coating the pipe with petroleum-based "mastic", synthetic, or cement will involve water cooling of the newly applied material. The water from these processes should be collected, transferred to cooling ponds, and treated by aeration and methods to reduce contaminants prior to release into natural waterways.

Regulatory Factors

A pipe-coating yard faces many of the same regulatory hurdles that are posed for platform-fabrication sites. State and local regulatory programs may be as important as the Federal permits that are required for dredge and fill and channel maintenance.

State and Local Role: State and local permits and certifications required for the development and operation of a coating yard will depend on the laws and regulations of the particular state, town or county in which the yard will be located. A new yard is likely to require zoning permission because of its size and the required water access facilities. State wetlands or dredge and fill permits are also likely to be required.

Federal Role: The Corps of Engineers issues permits for dredge and fill or alteration of the water areas of the United States. These permits are issued under Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Federal Water Pollution Control Act Amendments of 1972.

Other important considerations in particular situations include the Endangered Species Act and Federal highway decisions that require Fish and Wildlife Service comment.

Development Strategy

The decision to construct a pipe-coating yard is an economic one but beyond that, time, weather, and distance are important factors. A

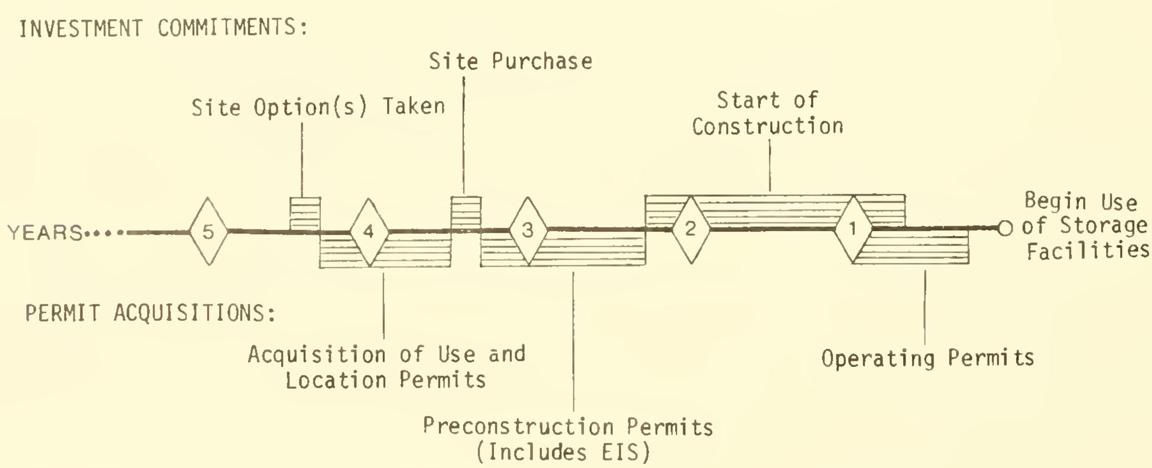
yard is a highly specialized facility and susceptible to the boom-bust syndrome that may accompany oil and gas development. Therefore a pipe-coating yard is usually situated in a region where underwater oil and gas pipelines are to be constructed in abundance. If the yard is located too far from the intended use area, it probably will not be economical to ship coated pipe long distances, particularly because of the increased weight of the coated pipe. The ideal situation is to take the coated pipe directly from the yard to the lay-barge where the pipe-laying operations are being conducted.

While logistically and economically convenient, the shorefront location of a pipe-coating yard is not a necessity. Not all of the pipe-coating operations need to be conducted on the shoreline. A marine terminal with a roadway connection to the main facility will allow the coated pipe to be shipped to the lay-barge. For a future yard the extra costs of transportation might be offset by the savings on the purchase of less expensive inland real estate. A one-hundred acre site can store approximately 300 miles of pipe and can represent an $8 to $10 million investment [26]. Because of the demand for large quantities of fresh water, both for the preparation of cement and for the cooling of newly treated pipe, local supplies must be adequate, and there must be assurances of a continuous supply.

2.3.6 Oil Storage Terminals

Onshore oil storage terminals are needed to receive, measure (meter), segregate, store, and distribute various grades of crude oil and refined products (see Figure 36). An oil storage terminal and a tank farm are synonymous. Terminals built to store the oil being produced from offshore fields have a constant inflow of oil from crude-collecting pipelines and an intermittent, very rapid outflow to tankers and refineries. Terminals built to store oil for one or more refineries have an intermittent, very rapid inflow of oil as tankers unload and a constant inflow from oil field pipelines; they have a smaller, constant outflow of oil to refineries. Oil storage terminals, then, are essentially surge tanks which help to eliminate interruptions and instabilities in an oil transfer and processing system. Oil storage terminals insure a continuous supply of crude oil from production areas to refineries.

Figure 36. Oil storage, project implementation schedule.



The primary purpose of oil storage terminals is to facilitate the rapid loading and unloading of tankers. There are two primary reasons that rapid oil transfer is desirable: (1) economic, and (2) logistic. First, tanker "downtime" during unloading is costly. The faster the tanker can unload and return for more oil, the greater will be its profit. Secondly, since stormy weather can often interrupt oil transfer operations, the faster that oil can be transferred, the shorter the good weather period required, and the fewer the chances for weather caused interruptions.

Description

An oil storage terminal consists of numerous large cylindrical steel storage tanks, oil-pumping and coolant-water equipment, interconnecting pipelines, an administration and control building, and large diameter crude-oil pipelines. A typical storage terminal handles a volume of one million barrels of oil per day (Figure 37).

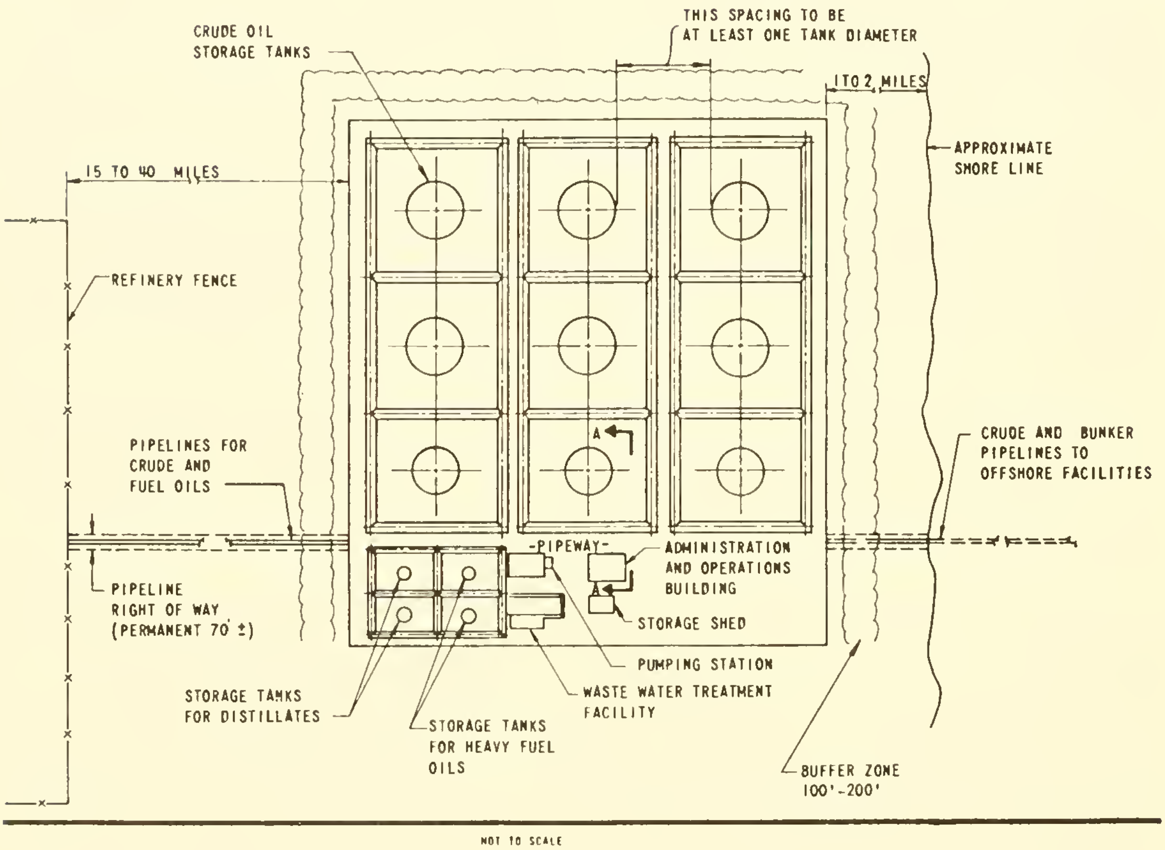
Surrounding an oil storage terminal, as well as each of its individual tanks, is an earth or concrete dike. The dike excludes floodwaters and, in the event of a tank rupture, retains the oil within its boundaries. These dikes also facilitate the collection and the treatment of storm water runoff to remove oil contamination.

Oil storage terminals also include several water collection and treatment systems. A small sewage treatment system is included to handle domestic sewage. A storm water collection system collects and discharges unpolluted storm water runoff. A third system is used to collect runoff plus water from processing that has come in contact with or is polluted with oil. Oil separation facilities and aeration ponds clean up these waters prior to discharge. These oil treatment facilities can be of considerable size if oil ballast water is discharged at the terminal, as it will be at an oil transfer terminal geared to oil export via tankers.

Oil storage terminals also have fire-fighting facilities. A pond providing water to extinguish fires will be constructed onsite if the terminal is not adjacent to water. A fire station with several pump trucks is required.

The steel tanks at an onshore oil storage terminal can be of two types--fixed roof or floating roof. Each time a fixed roof tank is filled, the hydrocarbon vapor in the void of the tank is displaced and, therefore, discharged to the atmosphere. A floating roof tank eliminates this problem and greatly reduces emissions because it moves up and down on the oil's surface accommodating only the volume of oil within the tank.

Figure 37. Schematic layout for a typical surge tank farm - example from 1.0 MM BPD refinery shown (Source: Reference 40).



An oil storage terminal will usually have an electric power substation on site. The substation is necesary to step-down high voltage power so it can be used to power the terminal's many pumps. From 5 to 15 megawatts of power may be needed in a large storage or transfer terminal.

The volume of storage necessary for a storage terminal serving refineries is dependent on the volume of flow between the terminal and the refineries, the size of the tankers served and the frequency of their arrival, and the duration of bad weather shutdowns.

Shown in Table 15 are the storage requirements related to where the petroleum is pumped from the vessel and the daily volume of oil handled

Table 15. Refinery Tankage Requirements Related to Storage Location and Throughput Barrels (Source: Reference 40)

THROUGHPUT		250 MBD[1]		500 MBD		1,000 MBD
Location of Terminal	Dockside	Mid-Depth	Deepwater	Mid-Depth	Deepwater	Deepwater
Crude Storage Requirements	1,000,000[2]	2,000,000	3,000,000	2,000,000	3,500,000	6,000,000
Crude Tank Configuration	4 x 250,000	2 x 250,000	3 x 500,000	2 x 250,000	4 x 500,000	3 x 500,000
		3 x 500,000	2 x 750,000	3 x 500,000	2 x 750,000	6 x 750,000
Heavy Fuel Oil Tank	45,000	60,000	65,000	60,000	65;000	80,000
Distillate Tank	30,000	50,000	55,000	50,000	55,000	70,000

1 MBD = Million barrels per day.
2 Barrels

by the terminal. Deepwater terminals are usually in more exposed locations and therefore need larger storage capabilities to mitigate the effect of shutdowns during bad weather.

An oil-storage terminal near the oil field usually necessitates another oil storage terminal near refineries because a down-surge due to unloading of field storage tanks onto tankers will obviously cause an upsurge of oil when the tankers unload at refineries. Thus if oil is to be transferred by tanker, two oil storage terminals are necessary.

Site Requirements

The site of oil storage terminals is largely determined by where offshore oil fields, tanker transfer terminals, and refineries are located.

Oil storage terminals which are built to store offshore oil for export are usually sited as close as possible to the shore. This aids in minimizing pipe-laying costs from the offshore field to the storage terminal and from the storage terminal to a transfer terminal. They will also be near a deep (up to 40 feet), sheltered harbor to insure safe tanker operations. Areas with considerable vessel activity will probably be avoided due to the danger of collisions.

Oil storage terminals that serve refineries will be sited between the tanker offloading terminal and the refineries served, in as central a location as possible. Terminals serving refineries do not need to be in immediate proximity to the coast, but can be 10 to 15 miles inland. Locations near the tanker transfer terminal are preferred, however, since different grades of crude are received and shorter receiving pipelines facilitate easier segregation of crudes into different tanks.

Shown below in Table 16 are the approximate flat land requirements

Table 16. Approximate Land Requirements for Surge Tank Farms (Source: Reference 26)

Surge Tank Capacity (barrels)	Land (acres)
1,000,000	17
2,000,000	37
3,000,000	50
3,500,000	58
6,000,000	95

for an oil storage terminal. If sloping land is used, more land will be necessary to provide equal amounts of storage as flat land areas. In sloping areas, the tanks can be located on tiers. Shown below are the diameters for various sized tanks with a height of 64 feet:

Tank Capacity (barrels)	Diameter (feet)
250,000	180
500,000	240
750,000	290

It can be seen that as volumes increase, a larger level area will be needed. To provide flat areas or tiers on sloping ground will necessitate considerable grading and even excavation. More earthwork will be needed to provide protective dikes around each tank. Thus, flat land is highly preferred because of the lower costs and fewer difficulties of constructing an oil storage terminal.

Oil storage terminals will be located above the 100-year flood zone if possible. In areas subject to tsunamis (tidal waves associated with earthquake and/or volcanic activity), they will be located at least a hundred feet above high water. High locations are also preferred because they permit gravity discharge of tanks, thereby reducing the power requirements of the terminal.

Oil storage tanks require foundations that are not subject to settling and that have a bearing capacity in excess of 7,000 pounds per square foot. If bearing capacity requirements cannot be met, pile foundations are necessary.

Construction/Installation

The construction of an oil storage terminal will require land clearing, grading and earth work operations, retention dikes, access roads, and parking areas. If the site is only slightly above water, considerable dredging and filling may also occur to raise the elevation of the site. These various operations will all require the use of heavy construction machinery such as bulldozers, drag lines, and graders.

Oil storage terminals are usually constructed by a consortium of construction companies, each of which specializes in a certain type of work. One company may do most of the earth work (grading and foundations), whereas another will fabricate the tanks and install the terminal's piping and electrical networks. These subcontracting companies will work for a principal contractor who often designs the facilities and then inspects and supervises the construction. The principal contractor

is responsible to the owner of the oil storage terminal who is usually one of a group of oil companies. Construction of a large oil storage terminal will require approximately two years.

Operation

Operation of an oil storage facility is highly automated, so that only a small work force is required. There is a constant inflow of oil from pipelines and outflow of oil to refineries, with intermittent but very rapid flow between storage facilities and tankers.

After oil is piped ashore, it is temporarily stored in tank farms prior to shipment for processing. By constrast, natural gas is piped directly from the offshore site to processing plants. The output from offshore production may involve both oil and gas which can be piped to shore in the same line. In that event, the oil and gas will be separated. The oil will go to a tank farm and the gas to the processing plant.

Community Effects

Oil storage terminals, or tank farms, are generally located in coastal areas to accommodate supplies from offshore pipelines, shore transfer stations and tankers at offshore moorings. Their site requirements for flat land are less stringent than those for other coastal projects because they can be constructed in tiers. These terminals are used to store either crude or processed products.

Employment: A large number of individuals are employed during construction; the size of the labor force can vary considerably depending on the number of tanks and the complexity of pumping systems. Approximately 565 workers would be needed to construct a facility capable of handling 250,000 barrels of oil per day [26]. To construct a 1 million-barrel-per-day storage terminal would require up to 900 workers. A storage terminal may be built in phases, in which case, lower levels of construction employment can be maintained for a number of years. Once the terminal begins operating, very few employees are required to run the facility. The staff includes maintenance and administrative personnel.

Induced Effects: During construction, wages will enter the local economy at a significant level, and employment should draw on available labor, especially at the unskilled level. Construction will be contracted with a number of firms from both the local area and outside. The major effect of a terminal after construction is unsightliness. The large tanks dominating the coastal view may lower land values or slow down price increases when compared with other areas. Examples of this potential effect are terminals in Tiverton, Rhode Island, and Fall River, Massachusetts. In Scotland, this potentially adverse effect was avoided by locating the tank farms off the shoreline and behind large berms.

Effects on Living Resources

An onshore oil storage facility has the following characteristics of particular concern to fish and wildlife: (1) oil storage tankers; (2) usually a marine terminal with channels and a berth; (3) service roads; (4) dikes; (5) cleared, level land; and (6) crude oil or petroleum product transfer.

Location: Usually an onshore oil storage facility is closely associated with another operation, such as an oil refinery or petrochemical plant. While a coastal location is not imperative for a storage terminal, economics have generally dictated a waterfront site. The ecological problems associated with such a facility usually concern pollution of the adjacent waters. Thus many of the adverse effects to fish and wildlife could be better controlled, or eliminated, by location at an inland site.

Locations at the mouths of bays and estuaries would aid the flushing and dispersal of silts stirred by boats approaching the facility and the dispersal of petroleum discharges from engines and other sources. Channels and harbors, which will require little initial and maintenance dredging, should be considered as the best choices for the location of the facility.

Design: If a marine terminal is part of the facility design, then effects on fish and wildlife will be minimized by using waterfront property. This would avoid the loss of fish and wildlife habitat from the filling of wetlands.

The need for adequate channels and a turning basin will cause dredging problems of turbidity and sedimentation, which may lead to the smothering of clams, corals, and other organisms. Oxygen depletion is also associated with dredging. Channels should be designed to limit the amount of initial and maintenance dredging. The channel route should be the shortest distance to the facility for dredging with minimum disruption of fish and wildlife habitat. The type of bottom material should also be considered. Loose, unconsolidated material requires maintenance dredging more often than does a solid substrate.

Dikes around the storage tanks should be high enough to hold all the contents of the tank if it should rupture. Every tank must have access by a service road to allow safe and effective fire protection along the dikes.

Construction: Open pile piers and floats should be built instead of sheet steel bulkheads for marine terminals. In the construction of steel bulkheads shores are often dredged to create a berth and to obtain fill to place behind the bulkhead. This alters the natural configuration of the shoreline and robs areas down the shore of needed sand by interrupting littoral drift. In addition,solid fill structures

tend to intercept, divert, and disperse water currents. This diversion may decrease available food supply and change water parameters, such as salinity and oxygen, leading to a significantly altered fish and wildlife habitat.

Oil storage facilities need to be relatively flat, and a major construction component will be heavy equipment operations to level the land. This requirement will result in the clearing of large acreage and will cause a drastic change in the microclimate. Species which previously occupied the sector will now find that area uninhabitable. Also, with the vegetation removed, erosion may occur if appropriate control measures are not taken. Without proper control excessive sedimentation may occur in streams and rivers, producing degraded fish habitats.

Operation: With the unloading of crude oil and loading of petroleum products, spill prevention is the primary concern. During such operations all vessels should be surrounded by an oil boom to contain any accidental releases of petroleum until they can be removed by vacuum truck, oil absorbing device, or other machinery. In case of an accident, automatic shut-off valves can terminate the operation without excessive losses of oil. The petroleum transfer must be supervised at all times, and a contingency plan must be routinely practiced to allow personnel to effectively react in time of an emergency.

Inspection of connecting hoses, seals, clamps, and other hardware must be performed on a regular schedule, and equipment with any sign of wear must be promptly replaced. Oil tankers must be inspected, and any indications of corrosion or malfunctioning parts must be corrected immediately.

Regulatory Factors

Construction and operation of oil storage complexes may require Federal, state, and local permits and certification.

State and Local Role: State and local legislation and other actions aimed at reducing the potential for adverse effects on the natural environment in particular may be stimulated by the threat of location of an oil storage terminal outside present ports and centers of industry. As with regulation of petrochemical industry construction discussed in 2.4.2 and of refinery construction discussed in 2.4.1, state and local governments may delay or block construction of new oil storage terminals. Zoning laws and state utility regulations are examples of potentially important land-use control mechanisms which can serve essential pollution abatement roles. This type of regulation may also impose design requirements on project components, such as clearing, grading, soil erosion, geologic structure, amount of impervious surfaces, and landscaping.

State permits regarding water and air quality may also be required for construction. In addition, separate or extended permits may be needed for operation and maintenance activities.

Federal Role: Federal permits may be required for activities affecting water and air quality at both the construction and operation stages of development. Activities regulated may include channel dredging, wetland alteration, and pipeline design and location. Dredge and fill activities for channels or wetlands are regulated by the Corps of Engineers under Section 404 of the Federal Water Pollution Control Act Amendments of 1972 and Section 10 of the Rivers and Harbors Act of 1899. The Fish and Wildlife Service advises in this process, and if the Service objects to Corps permit issuance, differences must be resolved between the Corps and the Department of the Interior in Washington. Typically permits are issued by the District Engineer with comment from the Field or Regional office of the FWS. Pipelines are discussed in Section 2.2.4.

Other important factors associated with coastal locations for oil storage terminals include the protection of endangered species habitat and operating permits related to air and water pollution.

Development Strategy

An oil storage terminal is required whenever transportation of oil between the production field and refinery involves shipment by tankers and pipeline. The reason is that tankers move oil in bulk quantities whereas production and refining processes handle oil volume at a fairly constant rate. Only small amounts of storage are needed when production feeds directly into crude oil pipelines that pump directly to refineries. Thus, oil production in areas with refineries will necessitate little storage in the field. Storage will be provided at the refinery--partly of crude and partly of products after refining. Production in remote areas will more than likely involve tanker transport and thus will require oil storage terminals.

Oil storage terminals are planned in conjunction with offshore pipelines and oil transfer terminals. Neither can be sited in isolation since they are part of a total oil transportation system.

Planning for the location of an oil storage terminal begins when the field development plans are mapped out. The route of the pipeline to shore and the location of the terminal are chosen to minimize the cost and logistics of constructing and operating the total transportation system.

The volume of storage necessary for an onshore oil transfer terminal depends on the production rate of the offshore field, the size of the tankers served, the frequency of their arrivals, and the expected duration of bad weather periods. Storage capacity should be sufficient so that

production from the field does not have to be curtailed and that a tanker has a minimal lodging time. The more hostile the sea conditions in an area, the larger the storage capacity needed.

2.4 PROCESSING AND MANUFACTURING PROJECTS

Pollution is a major concern of the petroleum processing and products manufacturing industry. Transporation problems, land use, community revenue problems, and the psychological effects of intrusion can also create difficulties in selecting a site. Few communities want a refinery or petrochemical plant because one or more of these problems is attributed to these facilities. Fortunately, existing infrastructure can handle much of the facility needs created by anticipated OCS oil and gas recovery in frontier areas.

The processing and manufacturing projects presented in this section are:

2.4.1 Refineries
2.4.2 Petrochemical Industries
2.4.3 Gas Processing
2.4.4 Liquefied Natural Gas Processing

2.4.1 Refineries

A refinery converts crude oil into useful petroleum products such as gasoline, fuel oil, and residual oil which is used by electric utilities. A refinery uses a series of processing units that separate crude oil by fractionation (distillation), convert it to other more valuable hydrocarbon compounds, treat it to remove undesirable constituents, and then blend basic stocks into more desirable end products.

Refineries are built in response to availability of crude and demand for refined products (see Figure 38). Since it is easier and less expensive to haul large quantities of crude in one extremely large tanker than to carry refined products in smaller tankers, refineries are usually located as close as possible to the center of demand (market area).

Figure 38. Refinery, project implementation schedule.

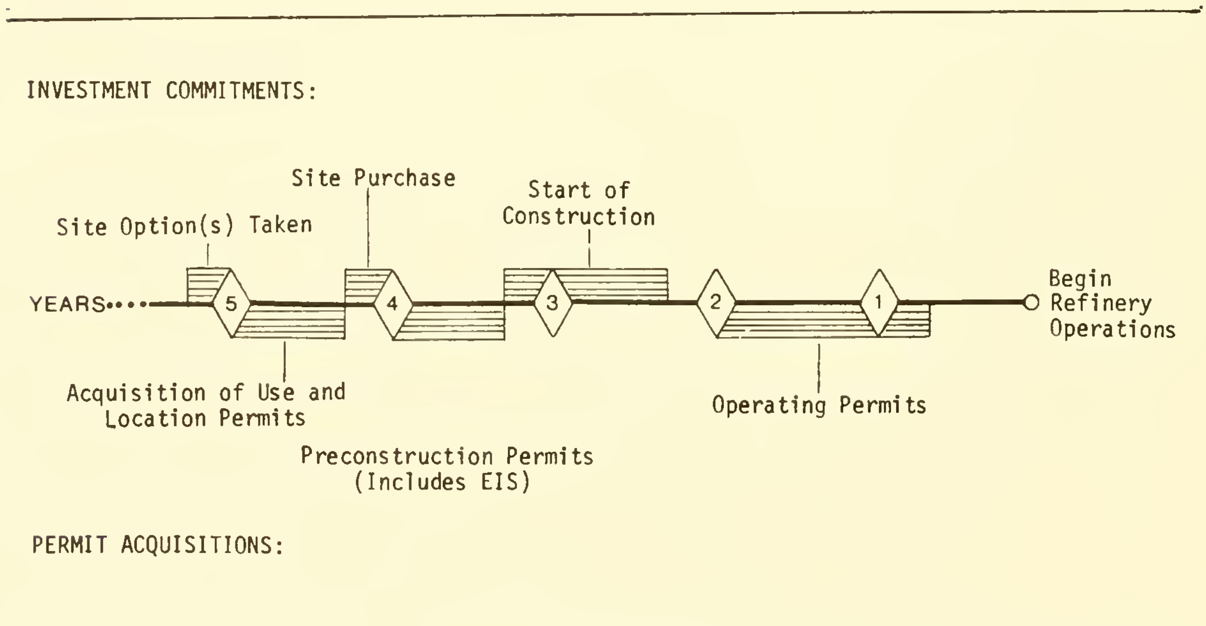


Table 17 illustrates the refining capacity, by state, in each of the six principal U.S. refining regions. It is interesting to compare refining areas to both established producing areas and to markets.

Refineries and offshore development do not correlate directly; a refinery is not required in the frontier area onshore to serve the offshore development. Therefore, investment to construct a refinery is likely to be separate from other OCS-related development. While the effects of substantial onshore development to support an offshore field, and of constructing and operating a refinery are individually substantial, the composite effect of both refineries and onshore support at a single site would be much greater. The probability that both types of development would occur together in the same place, however, is remote.

Description

The modern refinery consists of highly automated process units which physically and chemically alter all or part of the crude oil stream. In addition to the processing units, a refinery has a network of pipes and pumping stations, storage tanks for crude and product, wastewater treatment facilities, LNG storage tanks, and ancillary buildings (e.g., administration, machinery shop, fire station, warehouses, and truck loading terminals). Pipelines enter the refinery from oil storage terminals and leave the refinery to go to other oil storage terminals (2.3.6). The refinery is always surrounded by a buffer zone for safety.

Due to their large demand for cooling water, most refineries have large clarifiers to clean up water used in their cooling towers and other parts of the refining process. Collection and treatment of other wastewater necessitates rather extensive storm water and process water systems. Storm waters, if necessary, are treated in aeration ponds before discharge as they may have picked up contaminants. All process waters pass through oil separators and aeration ponds before discharge to surface waters.

In the "lower-48," refineries will all have railroad spurs for delivery of materials and heavy equipment during both construction and operation. Coastal refineries will usually have barge and tanker terminals. Electrical power substations onsite will step down the line voltage for use in the refinery.

Site Requirements

The siting requirements for a new "grass roots" refinery are extensive. Acceptable sites must meet locational criteria with respect to the market to be served, to existing oil industry infrastructure and to transportation access; and a site must meet rather stringent requirements

Table 17. Capacity of Principal United States Refining Regions (as of January 1976) - Exclusive of Hawaii and Alaska, United States maximum is 15.5 million barrels per day (Source: Reference 42)

Region	States	Maximum Capacity (barrels/day)	Percent of United States Mainland Refining Capacity
GULF COAST	Alabama	53,000	(38.5% in Texas and Louisiana)
	Mississippi	346,842	
	Louisiana	1,827,031	
	Texas	4,144,778	
	TOTAL	6,371,651	41.1
MID CONTINENT	Oklahoma	559,719	
	Kansas	468,940	
	Missouri	108,000	
	TOTAL	1,136,659	7.3
NORTH CENTRAL	Illinois	1,232,958	
	Indiana	561,160	
	Kentucky	169,500	
	Ohio	614,500	
	Michigan	151,395	
	Wisconsin	46,800	
	Minnesota	223,905	
	TOTAL	3,000,218	19.4
MID ATLANTIC COAST	New York	114,500	
	New Jersey	562,764	
	Pennsylvania	796,415	
	Maryland	31,211	
	Delaware	150,000	
	Virginia	55,000	
	TOTAL	1,709,890	11.0
PACIFIC COAST	California	1,993,503	
	Washington	383,105	
	Oregon	14,737	
	TOTAL	2,391,345	15.4
MOUNTAIN	North Dakota	60,163	
	Montana	164,016	
	Wyoming	194,557	
	Colorado	65,000	
	Utah	158,878	
	New Mexico	106,305	
	TOTAL	748,919	4.8

with respect to water availability, the elevation and slope of the site, and its foundation characteristics.

The desired location for refineries is as near to the product-demand center as possible. By centrally locating a refinery, numerous products can be distributed with a minimum of transportation difficulty and expense, and bulk shipments of crude oil can be received and shipped in large tankers. This means that refineries are usually located in proximity to urban (and oil consuming) areas. Air, water, and noise pollution standards may, however, cause refineries to locate in under-developed rural areas near a city and not within the urban area itself; the city may have already exceeded ambient air quality levels allowed; this would preclude construction of any new refineries.

A refinery in actuality is located on a line between its source of crude and its market so as to assure that the oil moves in one direction and incurs a minimum of back-hauls. Transporting oil to a distant refinery and then transporting products back to the region is usually economically infeasible.

Coastal refineries are usually located several miles inland from the coastline because property is usually cheaper and the chances for storm damage are decreased. They are, however, usually sited adjacent to deep navigable waterways because some crude end products (petroleum, coke, boiler ash, natural gas liquids) will be transported to and from the refinery by smaller tankers and barges. Examples of this are the natural gas liquids--extracted from raw gas at gas processing plants--which are used in gasoline manufacture. Petroleum, coke, and boiler ash may also be transported on barges.

A site near water is also needed because a refinery has extensive cooling water requirements. Approximately 4.5 million gallons per day will be consumed by a refinery processing 250,000 barrels per day [26]. Gulf Oil's Alliance Refinery, a 200,000-barrel-per-day unit, uses much more water. It requires 28 million gallons per day for cooling with 4 million gallons per day lost due to evaporation. In addition, refineries require another 2 million gallons per day for process water.

A new refinery has rather extensive acreage requirements. An acceptable site must include from 500-1,500 acres [43]. The Bureau of Land Management estimates 1,200 acres is needed for a refinery [21]. Gulf Oil's Alliance Refinery (200,000 b/d) is on a 700-acre site.

A new refinery requires level land that is above the flood zone and possesses soil-bearing capacities capable of supporting heavy structures such as retorts, fractionating towers, pumps, and catalytic cracking structures. Support for these heavy structures can be provided by piles, but there must be a firm formation into which the piles can be driven.

Level land is essential because it reduces the amount of earth work involved, reduces the complexity of piping systems, and reduces the pumping requirements within the refinery.

Refinery sites also require good transportation access. Transportation access is even more important during construction than during the operational phase, because thousands of tons of heavy materials such as cement, piping, pumps, and heavy prefabricated steel vessels must be brought in. Access by both barges and railroads is preferred. Access by one of these is absolutely essential. Good road access is also needed to handle the large number of vehicles during construction and the 200-400 workers during the operational phase.

A refinery site must have access to large quantities of electric power. Purchased electric power provides most of a refinery's power with a per-barrel-use of 2 kilowatt-hours for a simple refinery to more than 9 kilowatt-hours for a complex facility. It is estimated that 100,000 kilowatt-hours per day would be used by a 250,000 barrel-per-day refinery [26]. Some refineries may produce their own electric power.

In the United States, many refineries use natural gas as a refinery fuel rather than using a part of the input oil as fuel. Gas is cleaner, is easier to handle, and requires less expensive equipment. If gas is to be used as fuel, the site will need to be near a gas pipeline.

Lastly, a refinery is not sited in isolation, but is sited so as to fit into a petroleum producing, transporting, and distribution system. The best site, therefore, is one that fits into the existing petroleum industry infrastructure as well as the infrastructure system that will evolve in the future.

Construction/Installation

The construction of a large refinery will require approximately three years [26] during which it will employ approximately 3,000 workers: welders, pipefitters, electricians, equipment operators, and laborers [25].

The entire site will probably be cleared of vegetation to allow extensive grading and earthworks operations. Dikes will be built around all storage tanks and in refining areas. Stormwater and process water collection systems will be installed necessitating considerable trenching. Wastewater treatment facilities consisting of aeration and retention ponds will be excavated and diked. Parking lots will be graded. Finally, the refinery site will be landscaped to improve its appearance.

Construction of the refinery process units, piping, and storage tanks will require a great deal of metal bending, cutting, and welding. After units have been fabricated and connected, they will be sand blasted, cleaned with chemicals, and painted.

Numerous foundations for smaller buildings such as the operations center, fire station, and administration building will be dug with standard backhoes and trenchers. The buildings involve standard construction methods.

Barge and tanker terminals often will be installed by marine construction companies subcontracting to the main contractor. Jetties, piers, pilings and dolphins will be installed using barge-mounted equipment such as pile drivers and derrick cranes. Shorelines and bottom modification may take place in the area of the terminal, with the possibility of accommodating supertankers which would require water depths of 60 to 90 feet.

Operations

Refineries produce a number of petroleum products by physically and chemically altering all or part of the crude oil stream. The system is actually a series of complex units, depending upon the number and characteristics of the desired products.

The crude oil arrives at these highly automated facilities by pipeline or tanker and is stored. When it enters the production stream, it may undergo as many as four distinct processes: separation into light, intermediate, or heavy hydrocarbon groups; conversion, which chemically alters the groups into more refined groups (includes polymerization, catalytic reforming, and cracking); treatment, which removes the odorous contaminants such as hydrogen sulfide; and blending, which mixes base stocks to produce a wider variety of products.
After processing, the products are stored for later distribution by pipeline, ship, barge, or truck.

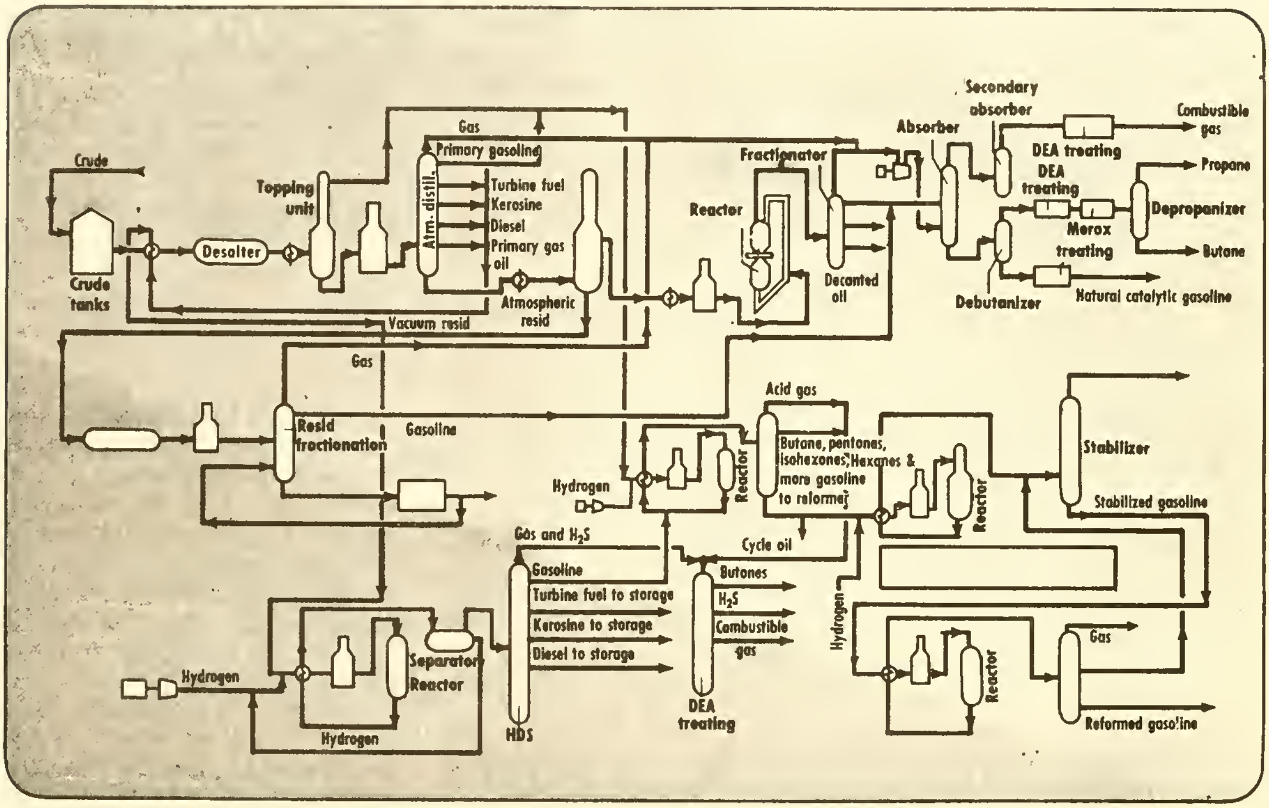
Community Effects

A refinery has the following characteritics of particular community interest; a large parcel of land, high employment, high investment, high service requirements, air pollution, and high requirements for water.

Employment: A refinery is the largest employer of the fifteen OCS projects during the construction phase. One study estimates the average work force to construct a refinery handling 200,000 barrels a day would be 1,800 persons with a peak force of 2,900. Further, 1,000 members of the peak level work force fall into skilled labor categories [28]. A project of this scale would attract many new or temporary residents unless it occurred near a major metropolitan area.

The operating staff for a refinery this size is approximately 550 persons. Subdividing this total, 55 are administrative support, 440 are

Figure 39. Example: refinery flow scheme (Source: Reference 44).



involved in operation and maintenance, with 396 of that total in the skilled labor category; and 55 are in a specialized support category, which includes laboratory and safety. The annual payroll for this facility would be 6.8 million dollars [28].

Induced Effects: Construction and operation of a refinery have several substantial effects on an adjacent community. While a major city would be little affected by this project, a small community could be totally disrupted. For the smaller community, the effect would be that of a "boom town" with a rapid influx of construction workers living in trailers or other temporary housing after all available units are occupied. Most of these workers will move on after the refinery is constructed, but substantial costs to the community will remain unless other local opportunities induce these individuals to remain in the area. The temporary residents will require services such as schools, protection, and water and sewerage, which will tax the financial structure of the community during their short residency. By contrast, the full level of taxable income from the refinery will not be forthcoming until it is operating.

After a refinery becomes operational, the total number of employees declines but is still a significant total for almost any community to absorb. Wages coupled with the number of new residents will greatly alter all aspects of community life. Pressure for construction of residential and commercial buildings will be intense. New public facilities and services will need to be provided as rapidly as possible. In some cases, temporary facilities and services should be considered in an attempt to coordinate the community investment level to the permanent employment level [45] rather than the peak construction employment level (2,900 to 3,000).

The refinery could affect the water supply of the community. With such large water requirements, surface and subsurface patterns could be altered. The community will also be concerned about possible contamination of local supplies and effects on recreational resources adjacent to the refinery.

An additional community concern is air pollution. Emissions and odors are potential problems associated with refineries. Therefore, in influencing the selection of a location, the community will encourage the refinery to locate downwind from any large settlements or heavily used recreation areas.

Effects on Living Resources

A refinery has the following characteristics of particular concern to fish and wildlife: (1) often a coastal location, usually on the waterfront; (2) large acreage of cleared, level land; (3) deepwater marine terminal; (4) navigation channel, berths, and turning basins; (5) offshore/onshore pipeline; (6) crude oil processing and storage equipment; (7) large amounts of cooling water; (8) access roads; and (9) potential for air and water quality problems.

Locations: Improperly located refineries and related facilities can have serious impacts on coastal water, as well as on air and aesthetic resources. For example, a 250,000 barrel-per-day refinery would require at least 4 million gallons per day of fresh water and would generate a variety of pollutants into the water that must be treated. The waters may contain oil and petroleum products, heavy metals, and process chemicals, which can can cause oxygen depletion, sedimentation, salinity changes, and toxicity.

In planning a refinery the sponsor usually desires to situate the facility as near the shorefront as possible to provide access to Very Large Crude Carriers (VLCC) or as large a vessel as possible and to provide a source of cooling and process water. It is not imperative to locate the facility on the shore because the crude oil, the end products,

and the needed water can be piped. Economics have generally dictated their presence on the waterfront.

Usually a refinery is closely associated with other operations, such as oil storage facilities or petrochemical plants. The ecological problems associated with such facilities usually concern pollution of the adjacent waters, thus many of the adverse fish and wildlife effects could be better controlled or eliminated by location at an inland site.

Location of marine terminals at the mouths of bays and estuaries would aid the flushing and dispersion of silts stirred by boats approaching the facility and of petroleum discharges from engines and other sources. Channels and harbors that will require as little dredging as possible should be considered as the best choices for the location of the terminal.

Relatively flat land is needed for the installation of refinery processing equipment. With level, shorefront land zoned for industry at a premium along the coast, the chances increase that wetlands will be filled to obtain the desired elevation. If this is done, important spawning/breeding and rearing areas of a variety of fish and wildlife will be lost. In addition, water circulation currents will be altered, perhaps leading to changes in parameters such as salinity, temperature, oxygen, etc.

Design: The need for adequate navigation channels and a turning basin will cause dredging problems of turbidity and sedimentation, which may lead to the smothering of clams, oysters and other sessile organisms. Oxygen depletion is also associated with dredging. Channels should be designed to limit the amount of initial and maintenance dredging. The channel route should be the shortest distance to the facility for dredging with minimum disruption of fish and wildlife habitat. Also to be considered is the type of bottom material, with loose, unconsolidated material requiring maintenance dredging more often.

With the need to service large tankers, the selected deepwater site will need ample space to allow maneuvering of the large ships, including turn-around capability. To reduce the chance of accidental oil spills, a fail-safe transfer system should be employed to keep human error to a minimum. A sophisticated monitoring system, which not only records unloading operations but gives indications of possible trouble sources, should be incorporated into the design.

With the possibility that crude oil tankers would be situated in deep waters distant from shore, provision should be made for general boat traffic to pass safely and easily without having to travel around the end of the pier. This will reduce the potential for boating accidents. The pier design should utilize open piles and avoid a solid-fill structure. The latter type alters the natural configuration of the shoreline and robs areas down the shore of needed sand by interrupting littoral drift.

In addition, solid-fill structures tend to intercept, divert, and disperse water currents. This may decrease available food supply and alter water parameters, such as salinity, oxygen, etc., which leads to a significantly changed fish and wildlife habitat.

If the refinery is to be located in a coastal site, the facility design should incorporate features to minimize intrusion upon nearby fish and wildlife habitats. Access to the plant should be via existing service roads with upgrading to allow for heavy equipment, but roads should not be open to the general public. Buffer zones, especially of evergreens, can protect wildlife from visual and noise intrusions into the habitat.

Dikes around the storage tanks should be high enough to hold all the contents of the tank if it should rupture. Every tank must have access by a service road to allow safe and effective fire protection. Dikes should not be routinely traversed by vehicles, and the top of a dike should not be utilized as a service road.

Construction: The sponsor must perform the coastal construction in a careful manner to protect adjacent aquatic and terrestrial areas. The scheduling of construction must avoid sensitive periods of species, including breeding/spawning, rearing of young, etc. Operation of heavy equipment must be performed to protect fragile environments, such as barrier beaches, wetlands and clam/mud flats. In many cases, particularly near wetlands, mats can reduce the impact of heavy equipment operations. Construction must involve stringent erosion control methods to prevent silt from entering streams and rivers where they could interfere with fish reproduction.

The need for flat land will cause large acreages to be cleared of vegetation and will cause a drastic change in the microclimate of the area. Species which previously occupied the sector will now find that area uninhabitable. Also, with the vegetation removed there is the possibility of erosion if appropriate measures are not taken to control it.

If the offshore/onshore pipeline is not suspended on a pier or piles, laying a pipe to shore will cause environmental impacts from the dredging needed to bury the pipeline (See Section 2.2.4).

Operations

The applicant's major environmental problem in operation will be in meeting pollutant discharge standards on industrial waste disposal and runoff water. The problems of oil spills are related to both the refinery and the transport of crude and refined products. The discharge of crude oil and petroleum products into estuarine and coastal waters presents

special problems in water pollution abatement. Oils from different sources have highly diverse properties and chemistry. Oils are relatively insoluble in sea and brackish waters, and surface action spreads the oil in thin surface films of variable thickness, depending on the amount of oil present. Oil, when absorbed on clay and other particles suspended in the water, forms large, heavy aggregates that sink to the bottom. Additional complications arise from the formation of emulsions in water, leaching of water soluble fractions, and coating and tainting of sedentary animals, rocks, and tidal flats.

Wildlife that become involved with an oil spill can die from ingestion of the petroleum or from loss of insulating capacity of their feathers or fur. Vacuum trucks and other skimming devices should be employed to remove any collected oil. Any damaged vessels, which transport petroleum products, should have an oil boom placed around them when necessary to prevent discharge into the water while repairs are being performed.

For refineries, problems with operations are by far the most important consideration affecting fish and wildlife resources and the consideration that the applicant will give the most effort to solving. If sited on the waterfront, designing the facility to avoid shoreline wetlands, and estuarine disturbances, particularly of wetlands, will be next in order. With the necessity to handle flammable gases and petroleum hydrocarbons, operation of the refinery must be performed to prevent accidental releases and ignitions so as to protect human and wildlife environments. In addition, emergency procedures should be practiced routinely so personnel can respond quickly and appropriately in time of need.

Regulatory Factors

Refineries are likely to be subject to special siting procedures at the state level. Local ordinances designed to minimize impacts on the natural environment may also be stimulated by refinery siting proposals. Federal regulations for dredge and fill and operating standards for air and water pollution are also important.

State and Local Role: State regulatory authorities may exist with the ability to override or supplement local regulatory controls over refinery siting. These controls are analogous to the zoning controls referenced in Section 2.1.3. Local reaction to these proposals is often adverse, and sponsors have been frustrated in many recent attempts as illustrated by Table 18.

Federal Role: If the refinery does not use a coastal location requiring dredge and fill or water access, federal laws will primarily influence design and operation of air and water pollution abatement devices.

Table 18. Refineries Planned but Not Constructed (Source: Reference 46)

COMPANY	LOCATION	SIZE (B/D)	FINAL ACTION BLOCKING PROJECT
Shell Oil Company	Delaware Bay, Delaware	150,000	State reacted by legislature passing bill forbidding refineries in coastal area.
Fuels Desulfurization (1)	Riverhead, L.I.	200,000	City Council opposed project and would not change zoning.
Maine Clean Fuels (1)	South Portland, Maine	200,000	City Council rejected proposal.
Maine Clean Fuels (1)	Searsport, Maine	200,000	Maine Environmental Protection Board rejected Proposal.
Georgia Refining Company (1)	Brunswick, Georgia	200,000	Blocked through actions of Office of State Environmental Director.
Northeast Petroleum	Tiverton, R.I.	65,000	City Council rejected Proposal.
Supermarine, Inc.	Hoboken, N.J.	100,000	Hoboken Project withdrawn under pressure from environmentalist groups. Considering site near Paulsboro, N.J.
Commerce Oil	Jamestown Island, R.I. Narragansett Bay	50,000	Opposed by local organizations and contested in Court.
Steuart Petroleum (2)	Piney Point, Maryland	100,000	Withdrawn due to pressure from environmental groups.
Olympic Oil Refineries, Inc.	Durham, N.H.	400,000	Withdrawn after rejection by local referendum.

(1) Refineries in question are the same in each case.

(2) Again being introduced.

Development Strategy

From the standpoint of the major oil companies and independent refinery companies, who own refineries, the most critical factor affecting the establishment of a "grass roots" refinery is the massive capital investment involved. At a cost of $1,500 to $3,000 per barrel-per-day capacity, depending on location and complexity [26], a new 200,000 barrel-per-day refinery can cost from $300 to $600 million. Such quantities of money represent large investments even to the larger oil companies. Money for a new refinery can be generated from company profits or by selling stocks and bonds.

The second most important factor affecting the decision to construct a new refinery is the considerable length of time before an investment in a refinery can begin to earn a return. This is especially critical when oil markets become unstable, for approximately four years are required to construct a refinery. If during this four year period the market changes significantly, the refinery can end up being a poor investment.

If construction of a new refinery were necessary, the petroleum company would attempt to find a site within the existing industry infrastructure or within an area that already was being developed by the petroleum industry. The company would employ this strategy in order to minimize time spent in obtaining necessary dredge-and-fill zoning, and other permits.

Sufficient instabilities and changes have occurred in petroleum markets in the last few years to indicate that there may be reluctance to invest in new domestic refineries. The most important instabilities, though, have been introduced by fluctuating interest rates and inflation. If both shoot upward in the midst of construction, the cost of completing a refinery can jump by tens of millions of dollars. These instabilities cast long shadows on the security of investing in hundred-million-dollar refineries and may herald a slowdown in new refinery construction.

Oil refineries are built in response to growing demand. There is, of course, some attrition of refining capacity as refineries get obsolete or inefficient; but the attrition rate is low, so new refinery construction is justified almost entirely on the basis of growth in demand.

If demand for products is growing slowly, it is usually more feasible to add refining capacity than to construct a major new refinery. First, a smaller investment is required, and its payback is faster. Secondly, the addition of a large increment of refining capacity in a region may either cause marketing problems for additional output or require the shutdown of older, yet functional, refineries.

Expansion of existing refineries is less expensive, since in most cases a significant portion of the infrastructure at an existing refinery can be utilized and land will already be owned.

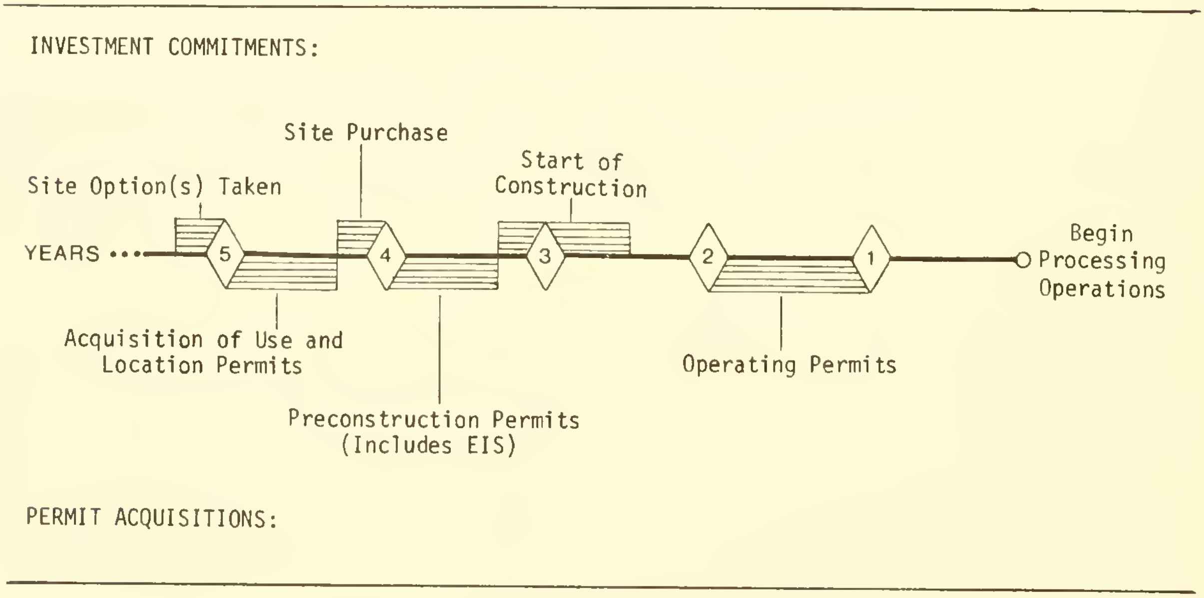
The infrastructure--the crude end product pipelines, tanker and barge terminals, storage tanks, and even technical know how--are extremely important in favoring construction in refining regions. If a refinery is to be constructed in an area without refineries, the refinery and the required infrastructure would have to be built, thus pushing costs higher.

New refineries will probably not be built in response to OCS finds because (1) offshore production rates will more than likely not sustain a refinery; (2) refineries are usually built in market locations and depend on demand growth there; and (3) any OCS production can simply displace foreign oil which is presently being refined in coastal regions.

2.4.2 Petrochemical Industries

A recent survey revealed that 622 petrochemical plants are operating in the United States; 22 percent of them are located in Texas. There are approximately 100 major petroleum refining and petrochemical plants in Louisiana, making that state one of the principal producers in the United States. A number of facilities in Louisiana are among the largest of their kind in the world. The most important reason cited for the growth of the petrochemical industry in Texas and Louisiana is proximity to raw materials. Other factors influencing the development of this industry have included the availability of existing facilities (see Figure 40), transportation, labor, land, and markets [47].

Figure 40. Petrochemical industries, project implementation schedule.



The petrochemical industry has undergone dramatic growth in capacity and profit in recent years. The most important product group is industrial organic chemicals, the basic materials from which synthetic fibers and plastics, rubber, lubricants, and hundreds of other products are made. Petrochemical industry sales in 1970 totalled almost $20 billion, about one-third of the total chemical industry sales. Employment exceeded 300,000 and its value-added approximated $10 billion, which is more than twice that of the petroleum refining industry. Primary organic petrochemicals, those whose manufacturing operations tend to locate close to "feedstock" (raw materials) sources, had a sales value of $7.4 billion [48].

Description

Petrochemicals are chemicals derived from refined petroleum products (e.g., naptha) and natural gas liquids. The chemicals directly produced from these raw feedstocks are classified into two main categories--olefins and aromatics. (Excluded from the definition are all fuel and energy products such as gasoline, fuel oil, natural gas, kerosene, lubricating oils, as well as asphalt, wax, and coke.) These basic petrochemicals are further processed through several intermediate mechanical and chemical stages into a wide range of chemical derivatives (such as dyes, resins, and fibers), from which many end products are made including paints, textiles, rubber, plastic products, and many others [48].

Several hundred petrochemicals can be identified. The six petrochemical groups underscored below are those which were produced in the greatest quantities in 1970. Among the specific types produced are [45]:

aromatics	sulfurized fatty bases
formaldehyde	oils
<u>benzene</u>	additives
perchloroethylene	leaded compounds
trichloroethylene	neoprene rubber
vinyl chloride monomer	chloroprene monomer
polypropylene	isopropyl alcohol
polyisoprene rubber	acetone
<u>polybutadiene</u>	metaxylene
polyisoprene	paraxylene
high density polyethylene	ammonia
<u>ethylene</u>	<u>propylene oxide</u>
low density polyethylene	ethane
synthetic glycerine	hydrogen gas
ethylene oxide	nitrogen
orthoxylene	argon
<u>styrene monomer</u>	<u>toluene</u>

A "petrochemical complex" is virtually undefinable as a physical entity but it is often an industrial area of large size, perhaps 300 to 400 acres or more. Of course there are many smaller manufacturers producing special products. A petrochemical plant has a "refinery look" to it. There are tanks, pipes, stacks, and metal buildings.

Site Requirements

A minimum of 300 acres is currently required for a complex able to support, for example, 1 billion pounds of olefins production per year. This may be representative of future petrochemical development that

would occur in regions where currently there is a minor amount of petrochemical manufacturing. These complexes would be tied largely to refinery development and would include plants producing those primary organic chemicals and key derivatives that are typically manufactured close to feedstock sources for economic reasons. Although the trend towards integrated refineries and petrochemical complexes will tend to decrease the net land requirements, this should not offset other pressures for more land. It is assumed that land requirements in the more crowded Mid Atlantic area will stay the same as more land-efficient installations are used there. The future land requirements for a petrochemical complex by region are assumed as follows [48]:

Region	Acres Required
New England	330
Mid-Atlantic	300
South Atlantic	350
Puget Sound	350
San Francisco Bay Area	300

Construction/Installation

Typically a petrochemical complex must be situated on solid soils of high load-bearing capacity because of the many activities involving heavy equipment. With its location usually in a coastal region there is a good probability that wetlands will be involved at some point in construction. The land must be cleared of vegetation. Unstable land must be excavated and filled with either sand or gravel to maintain an acceptable working surface.

The construction of a petrochemical complex will require land clearing, grading and earth-moving operations, construction of storage-tank dikes, access roads, and parking areas. If the site is only slightly above water, considerable dredging and filling may also occur to raise the elevation of the site. These various operations will all require the use of heavy construction machinery such as bulldozers, drag lines, and graders.

Installation of the processing equipment, storage tanks, foundations, pipelines, and pumping and electrical systems requires skilled welders, pipefitters, electricians, carpenters, and heavy equipment operators. Several hundred workers would be needed to construct a large facility.

Petrochemical complexes would normally be constructed by a consortium of construction companies, each of which specializes in a certain type of work. One company may do most of the earth work, such as grading and foundations; another will fabricate the tanks and install the piping and

electrical networks. These subcontracting companies will work for a principal contractor who often designs the facilities and then inspects and supervises the construction. The principal contractor is responsible to the sponsor which is usually one or a group of companies.

Operation

Current water requirements for a representative complex approximate 24 million gallons per day (Table 19). Water requirements should decrease

Table 19. Estimated Water Requirements for a Representative Petrochemical Complex (Source: Reference 48)

Plant	Annual Output (Million lbs)	Current Makeup Requirements (Millions GPD)
Orthoxylene	139	0.4
Toluene, Xylenes, Benzene	2150	1.8
Styrene	380	3.0
Ethylbenzene	87	0.5
Ethylene, Propylene	1560	6.0
Butadiene, Butylene	194	0.5
Cumene, Phenol, Acetone	520	0.8
Polyethylene	90	0.3
Ethylene Glycol	200	1.6
Vinyl Chloride Monomer	500	4.0
Polypropylene	70	0.2
Oxo Alcohols	245	1.3
Acrylonitrile	100	1.9
Cyclohexanone	237	1.6
TOTAL	6472	24 (approx.)

as industry becomes more efficient in using water, but should still be significant. Engineering contractors and industry sources indicate that a 50 percent reduction in water requirements should be achieved by 1985 [48].

Community Effects

A petrochemical plant has the following characteristics of particular community interest: (1) a large parcel of land; (2) high employment; (3) high investment; (4) high service requirements; (5) air pollution; and (6) water requirements.

Employment: Employment characteristics for construction and operation are similar to refineries, discussed in Section 2.4.1. In each case, a large construction force is required. After construction the employment level drops, although the plant is a major enterprise in terms of people employed and wages generated.

Induced Effects: Petrochemical plants and offshore development do not directly correlate. Production in an offshore field does not automatically indicate development of a petrochemical plant onshore. Therefore, construction of a petrochemical complex can be quite separate from the OCS-related projects described in this part of the report.

Effects on Living Resources

A petrochemical plant has the following characteristics of particular concern to fish and wildlife: (1) large amount of cleared, level land; (2) coastal location; (3) location near the source of raw material refined products; (4) air and water pollution potential; and (5) require large amounts of cooling and process water.

Location: In planning a petrochemical complex, the sponsor usually desires to situate the facility as near as possible to a refinery. A waterfront location is desired for marine access and for a source of cooling and process water. It is not imperative to locate the facility on the shore because the feedstock, products, and water can be piped. In view of the pollution potential and other environmental risks associated with a shorefront site, a non-waterfront location is desirable.

Sites adjacent to tidal streams, deadend harbors, small lagoons, and similar small or poorly flushed water bodies should be avoided because of their extremely limited capacity to accept and assimilate even small amounts of contaminants.

It is often desirable to direct industrial development to those areas which already have been modified and disrupted through existing industrial development or other land alteration. If industrial development

must occupy new areas, ecologically vital areas should be avoided. Sites such as dredge-spoil dumps which have had their ecological functions obliterated, might conveniently be developed for industrial use, providing any adjacent vital areas are preserved intact. It should be noted that problems arise with expansion in committed areas that are designated by the EPA as presently "air pollution impacts" and where new industry is essentially banned in order to prevent further air quality degradation.

There are many reasons to locate chemical industries back from water bodies and to provide for buffer strips of vegetation between the facility and the water's edge. The vegetated area provides a visual screen, a purification system for storm runoff, and a protective buffer for the ecologically sensitive shoreline,especially the wetlands. The setback should be placed above the annual flood line, which marks the upper edge of wetlands, and should provide a buffer wide enough to cleanse the maximum storm runoff it might receive in the 5 or 10-year rain storm. Flood-plain management and flood-proofing requirements must also be considered.

Design: The petrochemical plant's waste treatment needs must be incorporated into the community's long-term plan for environmental protection. For example, since the constituents of industrial effluent are usually quite different from those of domestic sewage, separate private systems may have to be constructed by the petrochemical plant and planned accordingly. Where discharge is allowed into the municipal collection network, private pretreatment units will probably be necessary to reduce the industrial waste flow to domestic strength before discharge, in order to protect the municipal facilities and the receiving waters.

Construction: The applicant must perform the site preparation with the utmost care to protect adjacent aquatic and terrestrial vital areas and generally productive habitats. Extra precautions will be necessary: (1) to minimize the alteration of water systems; (2) to prevent the erosion of soil; and (3) to eliminate the discharge of toxic or deleterious substances. Excavation and filling of areas near wetlands must be done so that sediments do not enter the wetland ecosystems. Revegetation of disturbed areas must be accomplished as soon as possible to reduce erosion.

Operation: The applicant's major environmental problem in operation will be in meeting pollutant discharge standards on industrial waste disposal and runoff water (Table 20). The problems of oil spills arise with both petrochemical plants and refineries. Unfortunately, the location of these facilities is such that spill and leak impacts are heaviest in the rich and vulnerable water of estuaries. New facilities should probably not be sited on bodies that have limited capacity for flushing.

In operation, petrochemical plants require large quantities of water for both cooling and processing purposes. Cooling water is used to reduce the heat generated during manufacturing operations. It does

Table 20. Estimated Future Water Pollution Loadings of a Representative Petrochemical Complex, in Tons per Year (Source: Reference 49)

Plant	Annual Production (million lbs)	(Best available technology) BOD	COD	Suspended Solids
Orthoxylene, Toluene, Xylenes, Benzene	2289	23	228	0-1
Styrene, Ethylbenzene	467	18	875	6
Ethylene, Propylene, Butadiene, Butylene	1754	43	442	20
Cumene, Phenol	425	12	517	4
Acetone	95	n/a	n/a	n/a
Polyethylene	90	3	19	2
Ethylene Glycol	200	3	98	0-1
Vinyl Chloride	500	12	110	10
Polypropylene	70	5	31	3
Acrylonitrile	100	3	25	15
Oxo Alcohols	245	21	1071	6
Cyclohexanone	237	11	111	0-1

not come into direct contact with the petroleum and is not thereby contaminated. However, it does present potentially significant thermal pollution problems and directly kills organisms sucked in with the cooling water. In addition, land subsidence may be caused in certain areas by excessive aquifer withdrawal.

Regulatory Factors

A petrochemical complex must comply with a complex set of air and water pollution control criteria derived in part from Federal legislation and in part from state and local programs. Site specific controls related to dredge and fill, pipelines, water supply, and transportation may also require permits or approvals from various public agents.

State and Local Role; State and local legislation and other actions aimed at reducing the potential for adverse effects on the natural environment in particular, may be stimulated by the threat of location of major petrochemical complexes outside present ports and

centers of industry. As with regulation of refinery construction discussed in 2.4.1 and of oil storage terminal construction discussed in 2.3.6, governments may delay or block construction of new petrochemical industries and refined products pipelines through zoning laws and state utilities regulations and water and air pollution abatement programs. The 1976 amendments to the Federal Coastal Zone Management Act of 1972 expand the responsibility of state coastal planners in this field. With an approved Coastal Zone Management Program, their plans may influence Federal permit and licensing activity.

Federal Role: The Federal role in the location of petrochemical industries is dependent on water access or alteration of wetland areas regulated under dredge and fill statutes. Industry standards affecting operations have also been specified under the air and water quality programs pursuant to the Federal Water Pollution Control Act Amendments of 1972 (PL 92-500) and the Clean Air Act. The primary Federal agency involved, therefore, is the Environmental Protection Agency.

Development Strategy

Petrochemical development will be affected by a number of factors, such as potential profit, feedstock availability, investment costs, available labor skills, and a receptive political/environmental atmosphere. Table 21 shows the relative ranking of six regions according to key locational factors. On the East Coast, development in New England should be minor with only a high OCS find yielding development of major petrochemical facilities. The reason for this is the relatively low level of expected refinery activity and the higher priority alternative fuel uses of that refinery output. Development in the Mid Atlantic should approximate the overall output percentage for petrochemical feedstock use. This development should occur despite environmental resistance because of the high market demand and attractive economics of petrochemical production in the Mid Atlantic [48].

In the South Atlantic, substantial development could occur under OCS development, exceeding that of the Mid Atlantic. The likely profitability, greater availability of feedstock, land availability, and a more receptive political/environmental climate should allow more significant development in this area. On the West Coast, petrochemical development should occur on a limited basis due to lower feedstock availability, limited market demand in the Northwest, higher investment costs, and potential political/environmental resistance. This should be more the case for San Francisco than for Puget Sound. In fact, under high OCS development, the latter area could become a net exporter of petrochemical products to other western regions by the year 2000 [48].

Table 21. Relative Ranking of Regions by Location Factor for Future Primary Organic Chemical Development (Source: Reference 48)

Locational Factor	Gulf of Mexico	Midwest	North Atlantic	Mid Atlantic	South Atlantic	Puget Sound	San Francisco Bay Area
1. Profitability	-	0	+	+	+	0	0
2. Feedstock availability (domestic and imported)[b]	+	0	0	0	+	0	0
3. Investment cost	+	0	0	0	+	0	-
4. Local market demand	-	+	0	+	0	-	0
5. Political/environmental resistance	+	0	-	-	+	0	-
6. Land availability	+	0	0	-	+	+	0
7. Skilled labor availability[c]	0	0	+	+	-	0	+
8. Local intra-industry technical support	+	0	-	0	-	-	-
9. Export demand location[d] advantage	+	-	0	-	+	0	-

[a]A "+" means that a region, for the factor indicated, has a relative advantage over most other regions for potential primary organic chemical production. A "-" means a disadvantage, and a "0" means no relative advantage or disadvantage.

[b]Takes into account competing demands for refinery products (e.g., fuel demand).

[c]Takes into account both the total demand and total availability of skilled labor.

[d]Takes into account local demand versus likely capacity; i.e., whether export demand opportunity can be capitalized on.

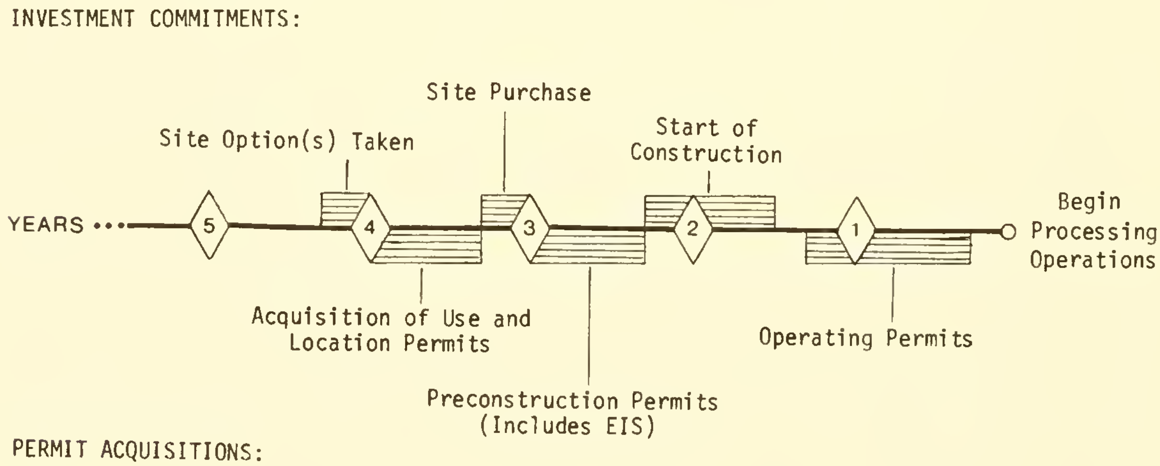
When a very large, rich gas find is made, a petrochemical (ethylene) plant may be attracted to the area. Such a plant uses ethane produced by the gas processing plant as feedstock. However, a gas find in a frontier region would have to be extremely large in order for a petrochemical plant to become an economically feasible proposition. Approximately 10,000 gallons per day of liquid hydrocarbons with a high percentage of ethane would be required to support a billion-pound-per-year ethylene plant. This large volume must also be sustained for ten to fifteen years to justify the location of an ethylene plant. The establishment of a large ethylene plant may induce additional downstream petrochemical activities to locate in the region [26].

2.4.3 Gas Processing

Offshore gas is obtained through a series of activities which include: (1) the drilling and completion of wells; (2) separating and dehydrating the raw natural gas into its constituent parts; (3) removing hydrogen sulfide if present; (4) recovering sulfur from the gas; and (5) storing and distributing the various forms of natural gas. These activities vary according to the composition of the well stream, the size of the producing reservoir, the proximity of the well to the shore and transmission lines, and other factors.

Processing plants are required to treat and process natural gas by separating methane out from the higher molecular weight compounds that are associated with natural gas (See Figure 41). Methane is the valuable component of natural gas. After separation, the gas goes through another process to take out carbon dioxide, hydrogen sulfide, and other unwanted consitutents. It is then transshipped to gas transmission pipelines for distribution to local utilities or to other companies for further processing.

Figure 41. Gas processing, project implementation schedule



Description

Gas processing plants are constructed if the offshore gas stream contains a sufficient amount of recoverable petroleum liquids. Being designed for the particular stream it processes, the plant may range in capacity from two million to two billion cubic feet per day (cf/d). Gas plants generally have a life of 10 to 20 years, depending primarily upon the expected life of the producing reservoir. A gas processing plant will have refrigeration units, compressors, power generators, a process building and tanks for the storage of recovered liquid hydrocarbons.

When gas is produced on an offshore platform, some partial processing of the gas stream usually takes place on the platform. If both gas and oil are produced, a separator is needed so the oil and gas can be metered and pumped through separate lines. If water is also produced with the oil and gas, a tank to remove water which is not contained in an oil-water emulsion is often used. For distant offshore production in the North Sea, Gulf of Mexico, and Pacific Coast the practice has been to separate free water and natural gas from the oil on the platform and then pipe the oil-water emulsion and gas to an onshore facility for treatment. When partial processing takes place on the platform, additional costs are incurred since space on a platform is much more expensive than it is on land, and additional space is required for both crew and equipment. Thus the tradeoffs between the differential cost of processing facilities determines the location of partial processing facilities [26].

Site Requirements

Land, preferably flat and well-drained, is required for buildings, storage facilities, pipes, towers, compressors, buffer zones, and parking lots. Actual space required for processing is small; much more space is required for safety reasons. The process, loading, utility, storage, and office areas are usually separated, with extra land around the plant perimeter. The amount of land required for a gas plant is related, but not directly proportional to volume of gas handled per day.

Gas processing plants require sites of 75 acres or less, of which 10 to 20 acres may be intensively used for buildings and structures. The remaining acreage is usually buffer zone. If necessary, partial treatment facilities can be constructed on sites as small as 2 to 4 acres.

When capacity exceeds 600 to 700 million cf/d, an additional processing unit is usually required, which takes up additional land. A typical plant handling a billion cf/d might require a total of 75 acres, of which 20 would be used for buildings and structures. A plant handling 200 million cf/d would require 50 acres [50].

Onshore partial processing facilities may be established to process natural gas and/or oil. A combined partial processing facility requires approximately 15 acres of land per 100,000 barrels of oil and associated gas processed [26]. A gas processing plant must be sited somewhere between the gas pipeline landfall and the commercial gas transmission line. The availability of land along this route is a primary determinant in plant siting, as are local land-use patterns and regulations. Pipeline transportation costs increase the farther inland the gas plant is sited, but this increase is usually out-weighed by the high cost of coastal land [26].

In a gas/oil mixture, heavier hydrocarbons are removed from the gas as quickly as possible after separation of the gas from the oil to minimize the possibility of plugging up the pipeline. Plugging, which reduces line capacity, is due to the condensation of hydrocarbons or the formation of hydrates on the inside of the pipe. As a result, gas processing plants and tank farms are situated close to each other and to the pipeline landfall.

Construction/Installation

The construction of a gas plant handling a billion cf/d would require about $85 million (1976 dollars) in capital investment. This would include condensate receiving facilities and full fractionation and storage for propane, butane, gasoline, and condensate.

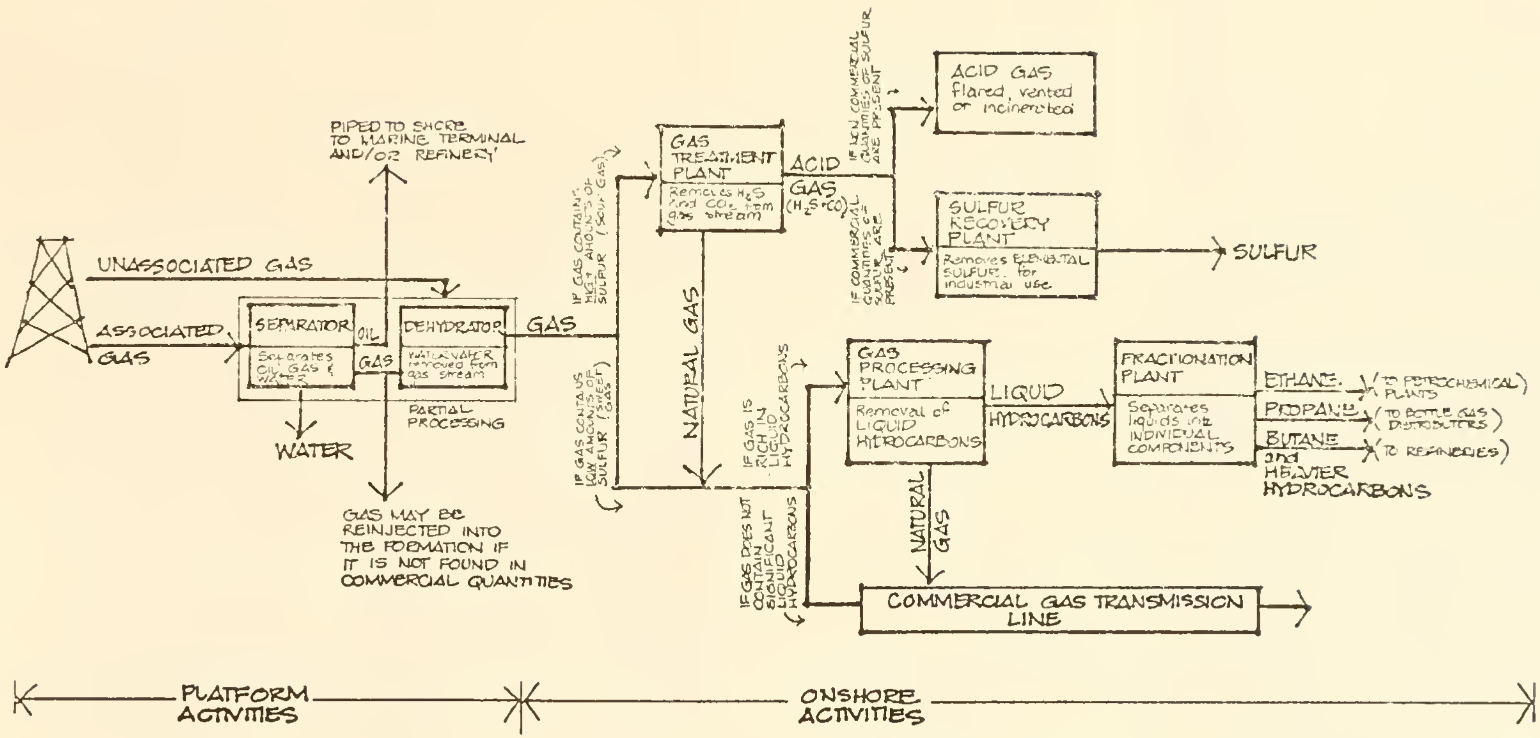
Environmental impacts vary with the site characteristics. If a water front location is chosen, environmental disturbances may occur due to dredging, filling, channel alteration, and spoil disposal. Inland locations reduce these disturbances. Since no unique, heavy machinery or processes are required on the site, site alteration and construction are not expected to result in severe noise or air pollution.

Operation

The nature of onshore gas processing depends primarily on two things: (1) the amount of ethane, propane, butane and other liquid hydrocarbons present in the gas; and (2) the amount of water and hydrogen sulfide (impurities) in the gas stream. An example process flow chart is shown in Figure 42. In general, the gas is produced at an offshore platform, partially processed to separate it from the oil and water in the well stream, piped to shore, treated to remove impurities, processed to recover valuable liquid hydrocarbons, and delivered to a commercial gas transmission line [26].

If the gas produced offshore is associated with oil, the gas will usually be separated from the oil and water on the platform by an oil-gas separator. Water is removed from the bottom of the separator,

Figure 42. A flow diagram of natural gas processsing operation (Source: Reference 50).



treated and discharged to the ocean. At this point, the gas still contains water vapor, which may be removed by dehydration on the platform. Dehydration is necessary because water vapor in the gas stream may freeze under pressure in underwater pipelines, interfering with the gas flow. If only a small amount of associated gas is produced by a given well, the gas may be reinjected into the formation in order to maintain pressure and permit recovery of oil resources [26].

The water demand for gas processing plants may reach 750,000 gallons per day, but most plants use less than 200,000 gallons per day. A typical plant uses about 1.5 gallons of water per thousand cubic feet of gas processed. The total water requirement for a gas plant varies depending on the cooling process used, with an air-cooled system requiring much less than a water-cooled system. When available, water is usually obtained from the nearest municipal water system.

A gas plant handling a billion cf/d would have an average demand of 7,500 kilowatts. Electric power will usually be purchased from a local utility or generated at the gas plant [26].

Gas plant products are transported by rail, truck, pipeline, or barge, depending upon what type of transportation is available and the location of markets for a particular product.

Community Effects

Gas processing plants occupy 50 to 75 acres and are located near the coast but not necessarily adjacent to the shore. These plants, which are usually located in rural areas, include buffer property for safety purposes and add to the employment base.

Employment: One recent study estimated that construction of a gas processing plant handling 300 million cubic feet/day requires 250 construction workers and 50 engineers [19]. A larger plant, with a capacity of one billion cubic feet/day, would employ a maximum of 550 workers during the construction phase [26]. After completion, a gas processing plant is relatively mechanized. A plant handling 300 million cubic feet/day might employ 21 persons: including 2 supervisors, 5 technicians, 8 operators, 5 maintenance persons, and 1 contract service person [26].

By contrast, a larger plant, processing 1 billion cubic feet/day, might employ 35 people. In the smaller plant, monthly wages for all employees would be $27,000. Of the employees, 60 percent would be hired locally; experienced supervisors and technicians would be brought from other areas. The employees who would be new residents would be those with higher wages. They will require homes and services in the local area.

Induced Effects: Induced effects from new employees moving into the area, approximately 15 individuals, would be slight and probably not noticeable in the local economy.

The facility will be located in a rural area for safety reasons. The adjacent community may need to provide services which include extending sewage lines, constructing new access roads, and other costly changes. Water demand for the facility may disrupt supply to other users from surface sources or alter the water table in small areas. The rural areas used by processing plants are usually unprepared for industrial growth. As part of a zoning change or building permit issuance, the local government may require the company constructing the plant to fund these improvements either jointly with the community or alone.

Effects on Living Resources

A natural gas processing plant has the following characteristics of particular concern to fish and wildlife: (1) offshore/onshore pipeline; (2) pipeline landfall; (3) gas processing equipment; (4) coastal site; (5) relatively level topography; and (6) access roads.

Location: The ecological problems related to a natural gas processing plant are primarily a result of the sponsor's desire to locate the facility at a coastal site on the pipeline which transports gas from offshore fields to onshore. The location is sought because costs can be reduced. Although a relatively small amount of land is needed for the facility, appropriate coastal land along the pipeline route is difficult to find. Efforts should be directed toward siting the plant on existing land rather than toward filling of wetlands to provide a location for the facility. The latter course of action will destroy important spawning/breeding and rearing areas of a variety of wildlife. Additionally, water currents will be altered, leading to changes in salinity, temperature, oxygen, etc.

Planning the coastal location becomes more complicated when the pipeline landfall is considered. Pipeline landfalls should be avoided in vital habitats, such as barrier beaches, dunes and sea cliffs, and endangered species habitats.

Locations of gently sloping topography where the terrain changes quickly from ocean/estuarine to upland are desirable. Many of the above complications in siting a gas plant can be avoided or reduced by placing the plant on upland areas rather than coastal. Pipeline corridor siting is of vital concern because construction through fish and wildlife habitat, especially in wetlands, may bisect the area. This may cause changes in water circulation and water salinity. Also, with the new water flow the area becomes susceptible to erosion and loss of vegetation from fast moving currents.

Design: If the gas processing plant is to be located in a coastal site, the facility design should incorporate features to minimize intrusion upon nearby fish and wildlife habitats. Access to the plant should be via existing service roads with upgrading to allow heavy equipment, but roads should not be open to the general public. Buffer zones, especially of evergreens, can protect wildlife from noise.

Construction: The sponsor must perform the coastal construction with the utmost care to protect adjacent aquatic and terrestrial areas. The scheduling of construction must avoid sensitive periods of wildlife, including breeding/spawning, rearing of young, etc. Operations of heavy equipment must be performed to protect fragile environments, such as barrier beaches, wetlands, and clam/mud flats. In many cases, particularly landfalls, mats can reduce the impact of heavy equipment operations. Construction near wetlands or on the upland must involve stringent erosion control methods to prevent silt from entering streams and rivers where there could be interference with fish reproduction.

Dredging of pipeline trenches in coastal areas should be done in a manner which will minimize turbidity and sedimentation, such as the employment of sediment screens and other techniques. If pipeline trenches are dug through wetlands, excavated material should be replaced in the trench instead of along the sides where it can interrupt water flow and change circulation patterns, salinity, temperature, and other factors. In addition new fill materials should be added where necessary to keep the elevation above the newly installed pipe the same as the surrounding wetland.

Operation: With the necessity to handle flammable gas and associated petroleum hydrocarbons, operations at the plant must be performed to prevent accidental releases and ignitions to protect human and wildlife environments. In addition emergency procedures should be practiced routinely so personnel can respond quickly and appropriately in time of need.

Regulatory Factors

Where siting flexibility allows selection of a site with suitable zoning, outside the immediate coastal zone, both state and local permits and Federal permits required for a gas processing plant may be minimal. Pipelines and related permits and construction standards are discussed in Section 2.2.3.

Pollution control regulations under the Federal Water Pollution Control Act and the Clean Air Act will also affect plant design. Permits are administered by both state agencies and the U.S. Environmental Protection Agency.

Development Strategy

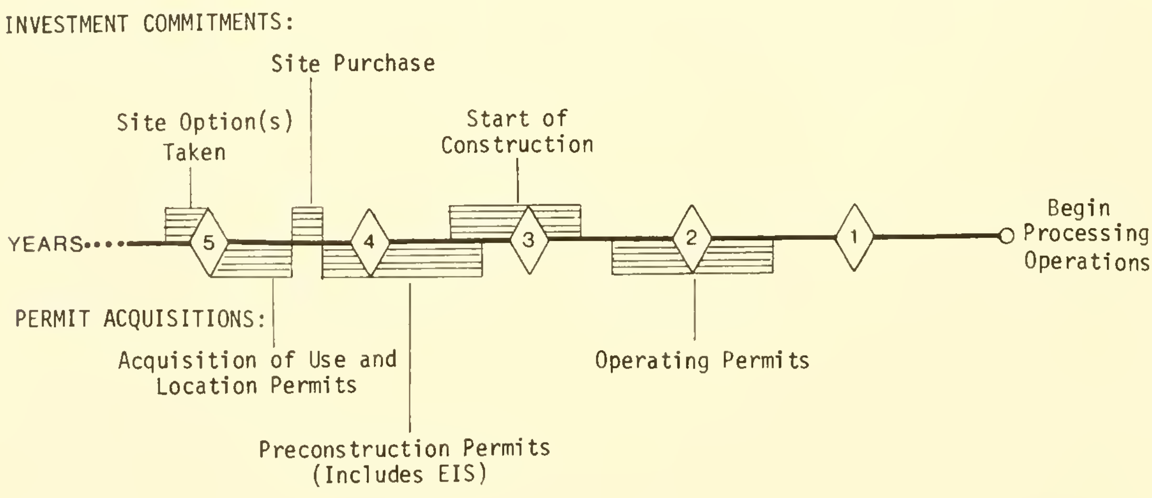
There is no fixed quantity of gas which justifies the development of a field (although 2 million cubic feet per day is generally sufficient). The major factors which determine whether a gas processing plant is built are the volume of gas discovered, the "richness" of the gas measured in gallons of liquid petroleum per 1,000 cubic feet of gas, and costs [26]. The richer a formation is in liquid hydrocarbons, the smaller a find needs to be in order to justify the construction of a gas processing plant. Gas must be found in sufficient quantity to justify the cost of processing, transporting, and distributing it. If an insufficient amount of gas is discovered, the well may be capped, or the gas may be reinjected into the well to maintain the formation pressure if commercial quantities of oil can be produced.

Gas is usually sold to a gas company at the well. The gas company is then responsible for constructing a gas pipeline. The oil company, which retains the rights to the liquid hydrocarbons in the gas stream, is responsible for constructing the gas processing plant. The cost of a gas processing plant depends on the quantity of gas, the richness of the gas, the degree of extraction of the key component (methane) and the number of separate products that are fractionated and stored [26].

2.4.4 Liquefied Natural Gas (LNG) Processing Plants

There are two types of Liquefied Natural Gas (LNG) processing plants. The liquefaction plant takes natural gas from a gas field, cools and compresses it, and then transfers the LNG to a specialized tanker for transport. The regasification plant receives LNG from the tanker, heats and vaporizes it and then sends the gas to a natural gas pipeline distribution system. The LNG tanker is an elaborate ship with a series of large self-contained tanks, which store the LNG under pressure and cold temperatures for the oceanic voyage to the regasification plant. LNG tankers are not designed to carry crude oil. Tankers currently being built can carry 785,000 barrels (125,000 cubic meters) of LNG, which is equivalent to 2.5 billion cubic feet of natural gas. The vessels measure over 900 feet in length, with a draft of more than 35 feet. They are approximately the size of a large aircraft carrier or a 100,000 ton displacement oil tanker [51]. (See Figure 43)

Figure 43. Liquefied natural gas (LNG) processing plants, project implementation schedule.



This involved system allows the utilization of gas from distant fields which are not able to reach markets by the construction of pipeline systems. Liquefaction, transport and regasification, as expensive operations, can only be economically viable where demand for gas is high and domestic supply is limited. Such a situation exists in

the United States where demand has been increasing and domestic gas production has been declining in recent years. The United States can expect to see additional regasification facilities, with the possibility of liquefaction plants in Alaska. Currently, an LNG liquefaction plant is under construction in Indonesia with its counterpart regasification plant proposed for Oxnard, California. Other LNG regasification plants nearing completion are at Cove Point, Maryland, and Elba Island, Georgia

Description

An LNG regasification plant generally has an elevated pier or trestle as much as 6,500 feet long to receive liquefied gas from the LNG tankers berthed offshore. (Cove Point has a tunnel.) The LNG is delivered to two or more storage tanks of 3 million cubic foot capacity before processing to return it to a gaseous state. The proposed LNG facility and trestle at Oxnard, California, consists of 218 acres, with 30 acres to be initially developed (expected to reach a maximum of 46 acres). The remaining acreage is either landscaped or undeveloped. The tanks are to be 80 feet high and 239 feet across. A reinforced concrete dike around each tank will be able to contain its entire contents. From the regasification plant pipelines carry vaporized gas to the gas company's existing distribution system [52].

Site Requirements

Due to the possibility of an accidental explosion, LNG liquefaction and regasification plants are generally located to avoid populated areas and should have substantial acreages of buffer, preferably wooded, between the plant and other land uses. The site size may extend to approximately 1,000 acres. Plant functions should be located no closer than one-third of a mile from neighboring roads, buildings, etc. and preferably should be further. The proposed site for an LNG facility must be level and capable of supporting heavy-weight storage tanks.

The plants are typically located on the coast and have an ocean connection due to the necessary tanker transport. While convenient, the coastal location is not a necessity. The processes which are conducted in either a liquefaction or regasification plant could occur at an inland site and probably at a greatly reduced cost in terms of acquisition. This may be particularly true where a large buffer is part of the facility plan. It is necessary to have a navigational channel and a marine terminal. Tanker drafts may exceed 35 feet so the terminal may have to be located some distance offshore or access channels and turning basins may be dredged. Sandy areas will make dredging operations easier compared to rocky seabottoms.

Construction/Installation

The construction of an onshore liquefaction or regasification plant requires the clearing of land in the immediate vicinity of the plant and making the topography as level as possible. This will require the use of heavy earth-moving equipment. With the selection of a coastal site, there is an unusually high probability that low-lying wetlands will be excavated and filled with sand and/or gravel to make a firm working surface. Storage tanks will have to be constructed with protective berm enclosures to contain fluids in case of leaks or ruptures.

A marine terminal will be constructed for unloading the LNG ship. If it is to be a close-in dock, there may be a requirement for a navigation channel to approximately 40 feet deep and a turning basin about four times the ship's length or 3,600 feet. If a channel and turning basin are not readily available, the sponsor is likely to build a long pipeline or trestle out to a depth adequate for LNG ships. Construction of an underwater pipeline would involve underwater trenching and filling. In some cases, ship-to-shore pipelines will be on a trestle, (Oxnard, California) or enclosed in a tunnel (Cove Point, Maryland), which could also serve to transport personnel between the plant and the marine terminal [53].

Operation

In receiving natural gas from an offshore gas field, a liquefaction plant first removes impurities and then cools the gas under pressure to approximately -250° F. This causes a reduction in volume greater than 600 times and converts the gas into a liquid. From this point until the time of regasification the gas must be maintained under constant low temperatures and high pressures. The liquefied gas is held in storage tanks until it can be loaded onto an LNG tanker for shipment. The basic constituents of a liquefaction plant are compressors and cooling apparatus, storage tanks, a marine terminal, underwater pipelines from the gas field, blowers, pumps, metering systems, administrative offices and maintenance buildings.

The regasification facility is essentially the reverse of a liquefaction plant having many of the same components, such as the marine terminal pumps and underwater pipelines. The difference is the presence of vaporizers which heat and reconvert the LNG to a gaseous state. A typical regasification procedure is described by the following and illustrated in Figures 44 and 45.

1. LNG tanker docks at the marine terminal.

2. Articulated unloading arms attach to ship.

3. Ship's pumps move LNG through underwater, buried pipeline to storage tanks of shoreside regasification facility.

4. Blowers transfer storage tank vapors back to ship to maintain positive pressure in ship's tank/or to be reconverted to LNG.

5. From storage tanks LNG is pumped by booster pumps to plant at 50 pounds per square inch (psi).

6. Primary pumps raise the pressure of the LNG to approximately 100 psi.

7. Secondary pumps increase the pressure to 1,250 psi.

8. LNG enters the water bath, gas fired vaporizer where it is converted to 60° F, 1,200 psi pipeline gas.

9. The natural gas is metered and placed into a gas company's pipeline for distribution to its customers.

The proposed LNG plant at Oxnard will initially process 522 million cubic feet/day (MMCFD) and expect about 75 ship arrivals annually. This averages to one ship every 5 days. At a maximum potential capacity of 4 billion cubic feet/day 565 ship arrivals may be expected, averaging three ships every two days.

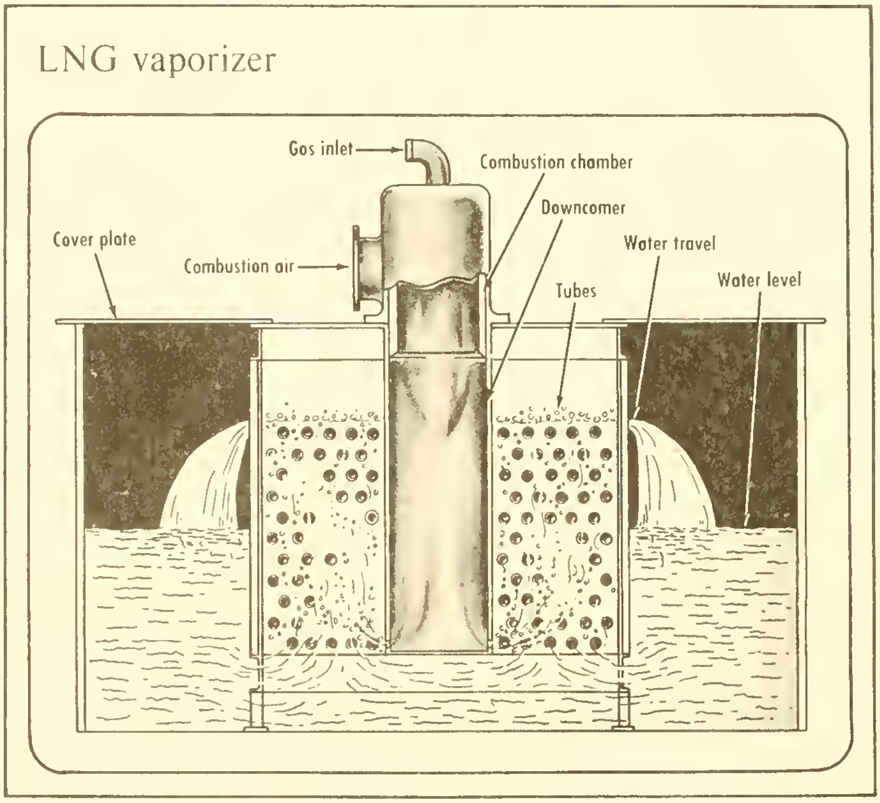
Community Effects

LNG liquefaction and regasification plants are located near the water and modify natural gas to make it more economical to transport. Conditions under which plants are built, therefore, are dictated by large sources of supply and large markets. The plant is located in a flat, shorefront site, preferably in rural areas, and employs very few skilled technicians after construction.

Employment: The average work force to construct an LNG regasificatic plant with a billion cubic feet/day capacity is approximately 600 workers. The Cove Point, Maryland, plant of Columbia LNG Corporation required approximately 900 workers at peak levels, but this increase was primarily to complete the tunnel to the offshore discharge terminal, an unusual requirement.

The operating staff of an LNG plant with this capacity is approximate 100 people. The three major job categories are operators, maintenance,

Figure 44. LNG vaporizer (Source: Reference 53).



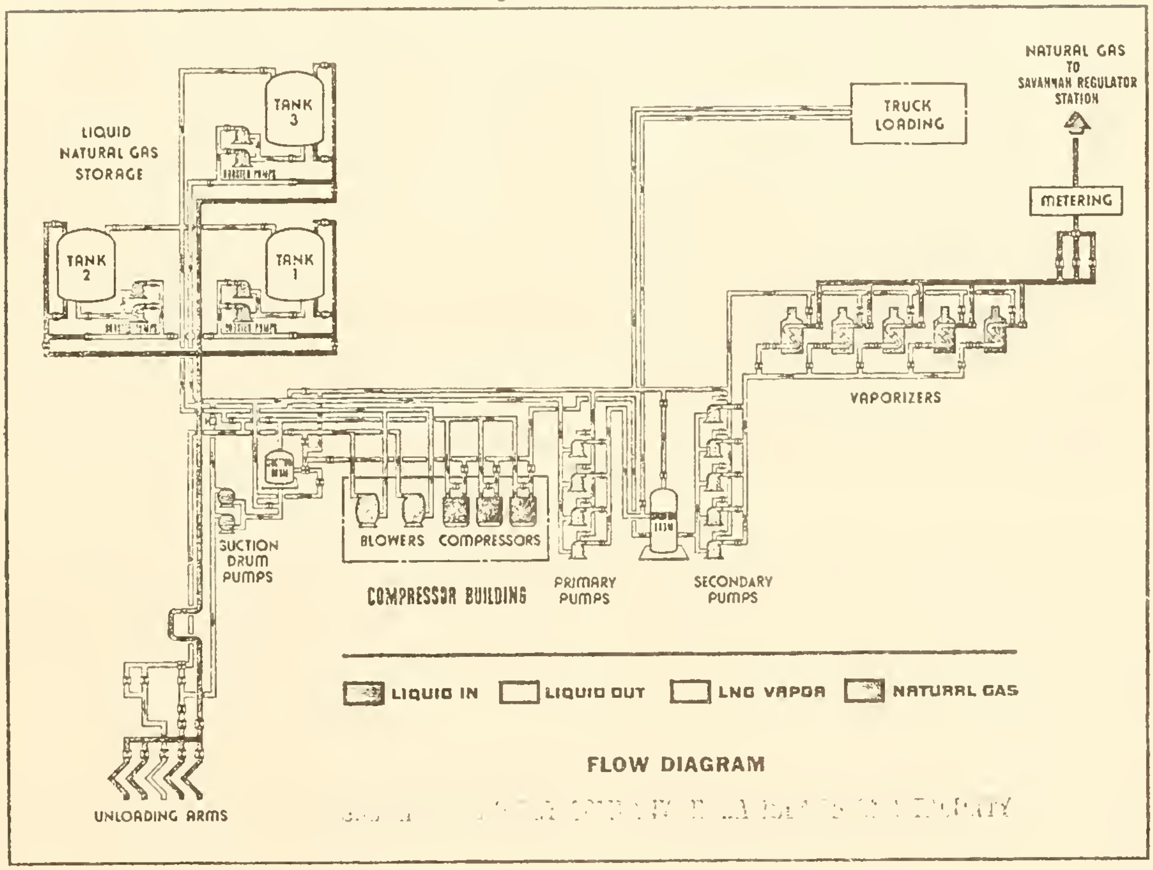
and unskilled utility workers. The Columbia LNG Corporation estimates approximately 50 percent of the operational employees in this rural area will be hired locally and the remainder will migrate into the area. By contrast, another major LNG plant in the United States, under construction in Savannah, Georgia, will probably be able to fulfill almost all its employment demands within the Savannah area [55].

Effects on Living Resources

LNG liquefaction and regasification plants have the following characteristics of particular fish and wildlife concern: (1) waterfront location; (2) deepwater marine terminal; (3) navigation channel, berths and turning basin; (4) cleared, level land; (5) offshore/onshore pipelines; (6) LNG processing and storage equipment; and (7) access roads.

Figure 45. Flow diagram of Elba Island LNG facility (Source: Reference 54).

Flow diagram of Elba Island facility.



Location: While approximately 50 acres is required for LNG equipment, large amounts of additional land are usually purchased for a safety buffer. The potential exists for explosion at a facility of this type, so the sponsor must attempt to locate plants some distance from populated areas. Special care must be taken to reduce adverse environmental effects on aquatic and terrestrial wildlife and on endangered species habitats. The ecological problems associated with LNG processing plants are primarily a result of the sponsor's desire to locate the facility at a coastal site to reduce costs of pipeline construction. While LNG must be unloaded from an LNG tanker at a marine terminal, the actual processing of the gas can occur on upland areas some distance from the unloading operation. To facilitate LNG deep-draft vessels the marine terminal may be located some distance from shore and connected by pier or tunnel to the onshore processing site.

Relatively flat land is needed for the installation of LNG refrigeration, compression, regasification, and storage equipment. With level, shorefront land zoned for industry at a premium along the coast, the chances increase that wetlands will be filled to obtain the desired elevation. If this is done important spawning/breeding and rearing areas of a variety of fish and wildlife will be lost. In addition, water circulation will be altered, perhaps leading to changes in salinity, temperature, oxygen and other measures of water quality.

Design: With the possibility that LNG tankers would be situated in deep waters distant from shore, provisions should be made for boat traffic to pass safely and easily without traveling around the end of the pier. This will reduce the potential for boating accidents. The pier design should utilize open piles and avoid a solid-fill structure. The latter type alters the natural configuration of the shoreline and robs areas downshore of needed sand by interrupting littoral drift. In addition, solid-fill structures tend to disrupt water currents. This may lead to a significantly changed fish and wildlife habitat.

The need for dredging adequate navigation channels and a turning basin will cause problems of turbidity and sedimentation, which may lead to the smothering of clams, corals and other organisms. Oxygen depletion is also associated with dredging. Channels should be designed to limit the amount of initial and maintenance dredging. Firm bottom soils will release fewer sediments to the water than loose, unconsoldiated types, which will require more frequent maintenance dredging.

Existing service roads should be maintained to allow heavy equipment, but roads should not be open to the general public. If a waterfront site is selected, the feasibility of transporting heavy processing and construction equipment by sea should be explored. Every storage tank should have its own access by a service road to allow safe and effective fire protection. Dikes surrounding tanks should not be traversed by service vehicles and the top of the dike should not be utilized as a service road.

Construction: The sponsor must perform the coastal construction with the utmost care to protect adjacent aquatic and terrestrial areas. The scheduling of construction must avoid sensitive periods of species, including breeding/spawning, rearing of young, etc. Operations of heavy equipment must be performed to protect fragile environments, such as barrier beaches, wetlands and clam/mud flats. In many cases, particularly near wetlands, mats can reduce the impact of heavy equipment operations. Construction must involve stringent erosion control methods to prevent silt from entering streams and rivers where it could interfere with fish reproduction.

If a tunnel is not constructed, the marine terminal should be connected by an open pile pier with floats instead of a sheet steel bulkhead. In the construction of steel bulkheads, shores are often dredged to create a berth and to obtain fill to place behind the bulkhead. This alters the natural configuration of the shoreline and robs areas downshore of needed sand by interrupting littoral drift. In addition solid fill structures tend to intercept, divert and disperse water currents. This diversion may decrease available food supply and change water parameters, such as salinity, oxygen, etc., leading to a significantly altered fish and wildlife habitat. If a tunnel is constructed a proper spoil disposal site must be selected to avoid filling wetlands and prevent seepage of contaminants into adjacent areas.

With the necessity for the onshore LNG site to be relatively flat, a major construction component will entail heavy equipment operations to level the land. This requirement will cause large acreages to be cleared of vegetation and will cause a drastic change in the microclimate of the area. Species which previously occupied the area will now find that area uninhabitable. Also, with the vegetation removed there is the possibility of erosion if appropriate measures are not taken for control. Without proper control there may be excessive sedimentation into streams and rivers producing degraded fish habitats.

Operation: Loading and unloading of liquefied natural gas must be performed with the utmost care to avoid human error accidents. In addition, contingency plans should be practiced routinely so personnel can respond quickly and appropriately.

Constant communication must be maintained between onshore operations and the offshore LNG tanker so sudden changes of temperature, pressure and other unexpected events can be corrected. This is in addition to automatic devices installed for safety purposes.

Regulatory Factors

State and local regulatory factors may exert an important influence on the location of LNG facilities. Federal jurisdiction over interstate gas pipeline facilities is also discussed in Section 2.2.4.

Special Federal regulations also set standards for Liquefied Natural Gas Systems (49 C.F.R., Part 192 -- Amendment 192-10). The Occupational Safety and Health Act, Clean Air Act, and Federal Water Pollution Control Act will also affect the design and operations of portions of the facility.

The specialized transportation facilities required in association with LNG Processing Plants are also subject to Federal control, primarily through the U.S. Coast Guard (See 2.2.5 -- Tanker Operations), but also through other agencies such as the American Bureau of Shipping and the Federal Maritime Commission.

Development Strategy

The strategy behind the importation of liquefied natural gas is that it can compete economically with gas from domestic fields, in spite of large capital expenditures for processing plants and the highly specialized LNG tankers, which carry cargo in only one direction. The costs of two conversions, plus transportation should not exceed the price of gas that might be available through domestic gas pipelines. With declining United States reserves, the importation of LNG may be the only way to maintain adequate gas supplies. Liquefaction plants being designed are expected to process three billion cubic feet of gas per day [56], whereas the economic minimum may be near 175 million cubic feet per day [57].

To reduce some of the steps in getting LNG into the gas pipelines one company has proposed an offshore, floating liquefaction plant. Although none of these have been built, this type of structure could be moved to an offshore gas field, liquefy the gas and load LNG directly onto a tanker as illustrated in Figure 46. There would be no need either for a prohibitively expensive offshore gas pipeline or for an onshore liquefaction plant, thus smaller gas fields could be developed that otherwise would prove uneconomic due to the above costs. With its mobility, the floating, liquefaction plant could be moved to utilize those resources.

Figure 46. Proposed design of offshore LNG plant - natural gas liquefaction on a semi-submersible storage and loading platform (Source: Reference 58).

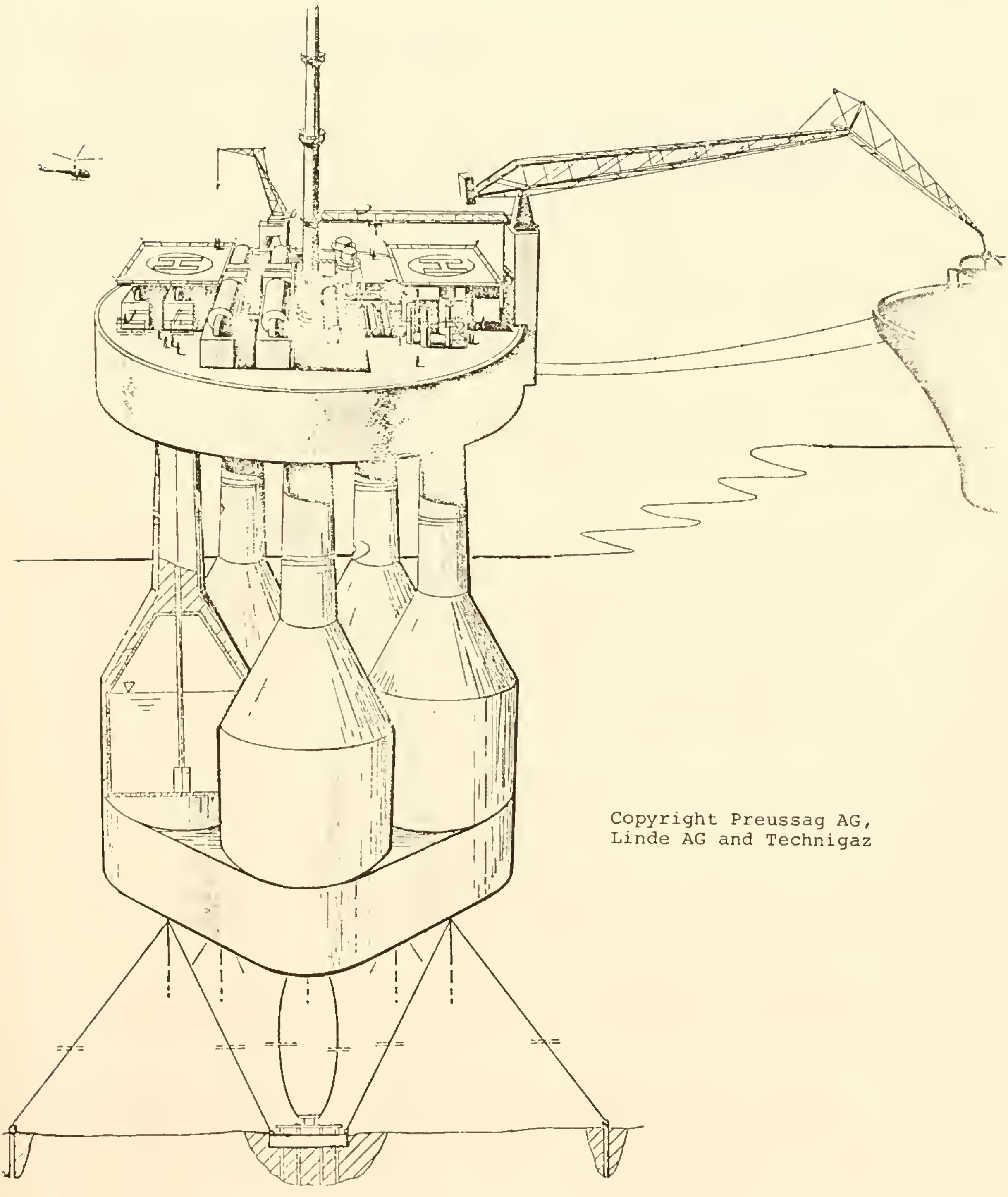


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PLATE I

A hypothetical (not to scale) layout of offshore and onshore components of an oil/gas recovery system constructed so as to show the type of units that could be used in a variety of OCS developments. [NOTE: This plate was furnished by courtesy of J. Ray McDermott Company for illustrative purposes only; no endorsement by the U.S. Fish and Wildlife Service nor its contractor is intended or should be implied.] Source: Reference 24.